Animal Manure and Related Biomass Feedstock Market Assessment and Preliminary Feasibility Study for a Papermill Biomass/CoGen Facility

Final Report

for

Southern States Energy Board
SERBEP Program

with

South Carolina Energy Office

Submitted by:

LINPAC Paper
139 Price Farm Road, Cowpens, SC 29330
Tel (864) 463-9090 Fax (864) 463-9585

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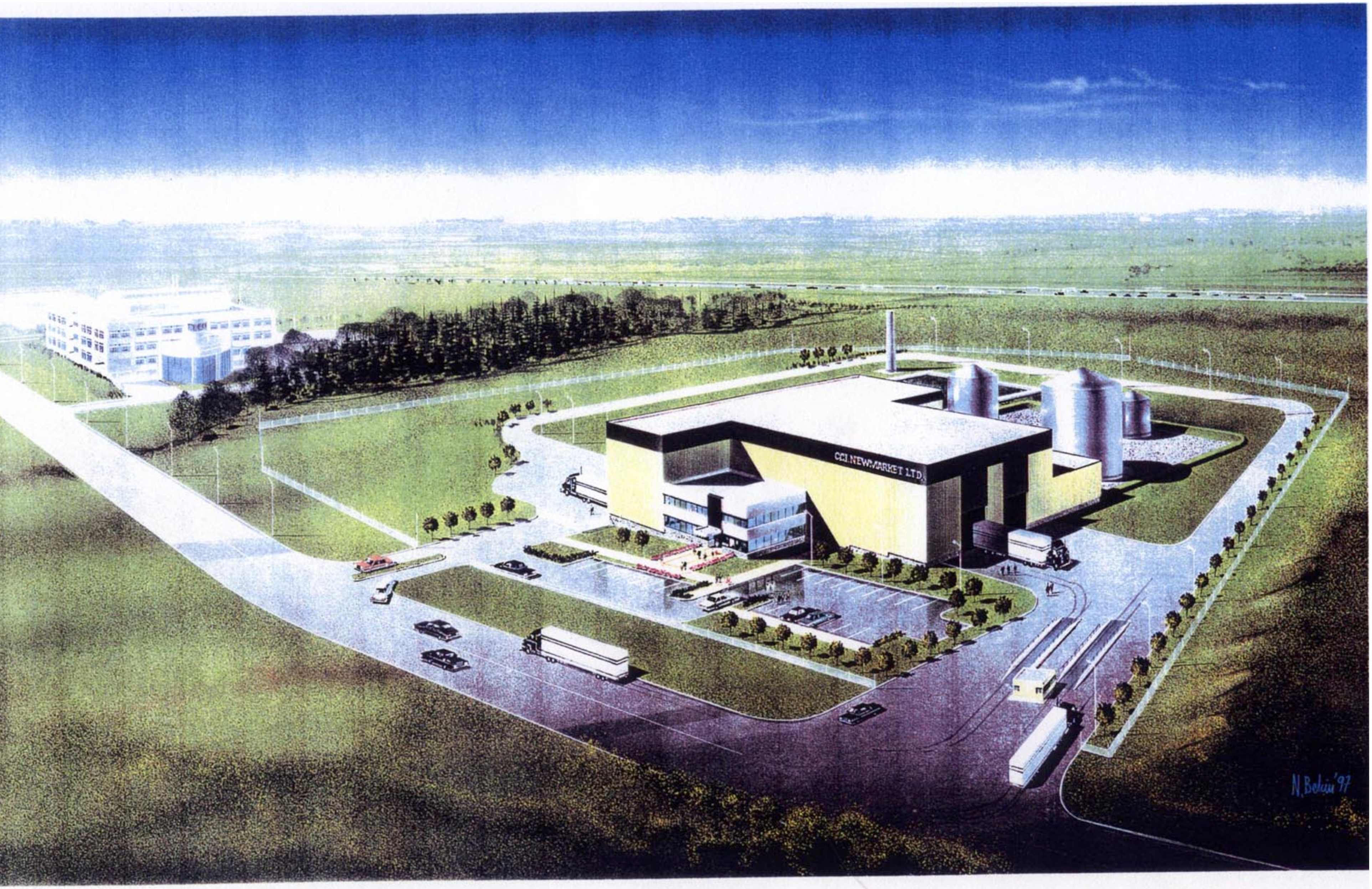
CCI NEWMARKET LTD.

Key Project Personnel

<u>LINPAC</u>

Jim Painter, General Manager
Joe, Gasperetti, Mill Manager [Project ACO]
Rob Bayliss, Project Manager

<u>Resource Recycling Systems, Inc.</u>

J. D. Lindeberg, Principal
Peter James Rudy, Vice President [Project Principal Investigator*]

<u>Canada Compost, Inc.</u>

Kevin Matthews, President

<u>South Carolina Energy Office</u>

Jean Paul Gouffray, Program Coordinator

<u>Southern States Energy Board</u>

Kathryn Baskin, Managing Director
Phillip Badger, Technical Director

*Note - Questions concerning the project and report should be directed to Peter James Rudy, Project Principal Investigator, RRSI, by phone at (734) 996-1361, ext. 236, or using e-mail at rudy@recycle.com.

Prepared by:

RESOURCE RECYCLING SYSTEMS, INC.

Consultants and Engineers in Resource Management
Recycling Based Manufacturing and Byproduct Reuse

416 Longshore Drive
Ann Arbor, MI 48105
phone: (734) 996-1361
fax: (734) 996-5595
e-mail: rrsi@recycle.com

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Linpac Paper

Project Background and Objectives

Linpac Paper owns and operates a state-of-the-art recycled wastepaper based mini-mill that produces 500 tons per day of premium linerboard at their Cowpens, South Carolina site. Linpac's linerboard is a premium product for use in the packaging industry. The Linpac mill is a large regional energy user in this growing rural area of South Carolina, and is seeking to improve and stabilize their mill's energy situation in an area where demand has negatively impacted energy cost and availability. Linpac Paper has performed this Southeastern Regional Biomass Energy Program study in partnership with the Southern States Energy Board and South Carolina Energy Office to determine the preliminary feasibility of a proposed Biomass/CoGen facility on the Linpac linerboard mill site. In support of this project, Linpac has also developed project partnerships with Resource Recycling Systems, Inc., (RRSI) a leading resource management firm located in Ann Arbor, Michigan, Canada Compost Inc. (CCI), of Newmarket, Ontario, Canada, the North American licenser of the BTA anaerobic digestion technology for biogas production, and Enron North America, of Houston, Texas, a leading energy based corporation.

Linpac has performed this study to resolve initial animal manure and biomass raw material feedstock issues including regional availability, procurement methodology and expected feedstock cost, as well as conceptual facility design and requirements, technical feasibility, and preliminary financial analysis estimates. Linpac has performed initial investigations into cogeneration capability at their site, as well as into several other energy and steam purchase and/or power generation options. Linpac's energy and steam requirements are a significant component of mill costs, and with energy markets escalating, the resolution of this problem is a critical area of concern for Linpac management. It is important to resolve these initial feedstock and facility issues specifically for the Linpac site and rural Cowpens region.

The project objective provides for goals that act towards defining and resolving the animal manure and biomass feedstock, and the preliminary feasibility for the project technical areas of concern. The project goals are as follows:

- Provide an animal manure and related biomass feedstock market assessment, suitable for raw material basis work for a Biomass/CoGen facility tentatively planned for the Linpac site.
- Provide a rudimentary animal manure and related feedstock market assessment and raw material input evaluation of the adjoining SERBEP states, suitable for raw material basis work for a Biomass/CoGen facility tentatively planned for the site.
- Detail the animal manure and related feedstock's regional waste management practices.
- Provide technical and engineering work to conceptually define the Biomass/CoGen facility.
- Provide a preliminary feasibility evaluation of the proposed Biomass/Cogen facility.
- Provide for regional energy market assessment, to be used with the Linpac site requirements.
- Provide initial preliminary capital cost estimates, return on investment estimates, and preliminary business planning due diligence effort to define the opportunity.

This study provides valuable information through the feedstock market assessment, as well as the preliminary feasibility work for the proposed facility. The study conceptually defines a model Biomass/Cogen facility that would be suitable for many energy-intensive industries such as Pulp and Paper, Food Processing, and related industries. The work provides an initial determination of the feasibility of the Biomass/Cogen concept and valuable data that is useful for future work on the Biomass/CoGen facility and many other SERBEP project areas.

Methodology

No single source provides a clear accounting or estimate of animal manure and biomass waste generation. For this reason, a variety of information sources were evaluated in the assessment of the generation of compostable organic wastes in South Carolina and the SERBEP region. The engineering workscope involved providing a conceptual view of the proposed Biomass/Cogen facility using the BTA technology as a basis. The conceptual engineering and technical work identified major equipment and systems for the facility, with corresponding capital cost estimates.

Literature and Research Methodology

A literature search and investigation for relevant materials was successfully conducted. Information and documentation that support the remaining tasks and project work were found. A summary of significant bibliographic references is included in Appendix A of this report. Copies of specific articles or materials can be obtained from RRSI upon request. The materials were collected from the following sources:

- Books/Handbooks/Proceedings/Symposium Publication
- Magazine Articles/Publications
- Internet Accessible Websites/Documents
- Recent News/Press Releases
- Linpac/RRSI/CCI/Enron/CEPES In-house Data

For the research, in-house materials and data from the project partners have provided a good baseline for future project task requirements and reference. The materials provided are applicable to the technology and provide engineering and technical information useful for future task work. The general literature search has provided excellent background materials and documentation, which has turned up important information about anaerobic digestion technology for biogas generation and production, and disposition of key facility residuals such as compost. Additional information pertaining to the regulatory environment, energy market, compost market and related project peripheral concerns has been obtained.

An initial review of the CCI literature for the BTA anaerobic digestion process and a site review of the CCI Newmarket facility suggest that application of the technology in the SERBEP region is potentially feasible and beneficial. This patented anaerobic digestion technology has been found to offer some of the best process efficiencies observed. It appears to be capable of delivering a high quality biogas product from a variety of biomass feedstocks including animal manures and other related wastes. Given appropriate feedstocks and "recipes", the facility residuals will consist of a biomass byproduct that provides a good solid residual material appropriate for composting and sale.

An initial survey of literature on biogas generation indicates that animal manures, agricultural crop residues, animal renderings, food processing waste, human manures, industrial pulp and paper waste, forest products residuals and other organic materials are often usable as feedstocks for biogas generation. Some industrial pulp and paper by products must be handled with care as feedstocks because of the presence of residual biocides, which adversely affect the microbes, which carry out anaerobic digestion. For a continuously operating anaerobic digestion system such as that implemented by CCI/BTA, various “recipes” or mixes of a range of feedstocks are developed for optimum performance. Industry data categorized by SIC code suggest that a variety of viable feedstocks may be available in the region of probable facility siting near Linpac Paper in Cowpens, S.C. region.

Solid organic residuals are expected from biogas production facility in most cases, suitable for biomass compost production. Depending on the feedstocks, several residuals from the biogas generation process may be obtained, some of which may be marketable. In addition to the compost fraction, marketable facility residuals may include plastics, metals, aluminum and glass. First, depending on the feedstocks, there may be reject material not appropriate for digesting. This is particularly true if mixed municipal solid waste (MSW) or other mixed solid waste is used as feedstock. These rejects may in some cases be sorted into recyclable materials and non-recyclable materials. Markets may be sought for reject plastics, metals and glass. Other miscellaneous reject materials would most likely be landfilled. Liquid residuals may also arise from the digestion process. Depending on the water balance in the digestion process, the liquid residual may be an excellent fertilizer appropriate for land application. Land application is regulated at the federal and state levels, and appropriate permits must be obtained.

Feedstock Generation Survey Methodology

This report's feedstock generation survey relies on a sector-by-sector waste generation estimate of key industries and an analysis to determine the quantities of organic waste material potentially available. For animal manure and residuals, the estimates were based on animal head counts, and per animal waste generation standards applied for published and/or developed conversion factors. For non animal biomass estimates, employment data for Standard Industrial Classifications (SIC) codes for target industries and sectors, which are available county-by-county for a range of target industries, were compiled and pounds per employee per day waste generation standards were applied using published and/or developed conversion factors. The work and methodology presented in this task's analysis seeks to answer the following basic questions:

- Is it reasonable to assume that there are suitable types and quantities of animal manure and related biomass organic feedstocks for the proposed facility?

- Can Linpac work within the existing waste disposal and recovery infrastructure to cost effectively obtain the types and quantities of feedstock needed by the facility?

In addition to the tabulated results, the feedstocks were mapped by type to provide a conceptual idea of the regional availability. Additionally, with this universe of potential organic wastes identified, an assessment of the recoverable portion was estimated, based on a review of research papers and the professional experience of RRSI. The report also provides strategic recommendations for proceeding with future animal manure and biomass feedstock procurement work necessary to support the facility.

For this feedstock generation estimates several distinct sectors and used data sets which were derived as described below. Appendix B contains the complete list of feedstock generation multipliers or conversion factors used, as well as the reference bibliography used to develop and cross check each factor for use in this work.

Geographic Distribution - Animal Manure:

'Animal Manure' is represented by the total cow, hog, poultry or sheep manure estimated for the target area. Animal manure was estimated by multiplying the number of animals in a given county (hogs, sheep, or cows) by a species-specific multiplier to arrive at a manure total per county per year. Animal populations were obtained from the *USDA Census of Agriculture,* 1992. Multipliers were obtained from the *On Farm Composting Handbook*.

Geographic Distribution - Animal Slaughter Residuals:

'Animal Residuals' is represented by the biomass animal waste that result from slaughtering of cow, hog, poultry or sheep. Since the majority of animal slaughter residuals are already used (i.e. animal feed production, etc.) this biomass waste is calculated from the undesirable biomass solids only, which result from water treatment activity. Animal residuals were estimated by multiplying the number of animals in a given county (hogs, sheep, or cows) by a species-specific multiplier or conversion factor to arrive at a residuals total per county per year. The methodology used to calculate the multipliers and conversion factors is provided in Appendix B. The animal residual totals for a specific region could then be tabulated. Animal populations were obtained from the USDA Census of Agriculture, 1992. Conversion Factors were obtained from data provided in the *Council for Agricultural Science and Technology's (CAST)* 1995 edition of *Waste Management and Utilization in Food Production and Processing*. The animal residual conversion factors generated using the CAST data were checked against other animal residual factor sources.

Geographic Distribution - Food Manufacturing Biomass Waste:

'Food Manufacturing' biomass waste is represented by the biomass waste from various industrial food processing and manufacturing sectors, for example fruit and vegetable preserving, sugar and confectionery, dairy product manufacturing, etc. The number of employees in every food and beverage manufacturing industry were totaled for each county. This number was then multiplied by a food manufacturing specific multiplier to estimate the level of biomass generated as waste by these industries. Employment figures were provided by the 1998 County Business Patterns survey of the Economic Census. See Appendix B.

Geographic Distribution - Food Service Biomass Waste:

Food Service' biomass waste is represented by the biomass waste residuals coming from hotels, restaurants, grocery stores, etc. The number of employees in the food service industry was totaled for each county. This number was then multiplied by a food service specific multiplier to estimate the level of biomass generated as waste by these industries. See Appendix B.

Geographic Distribution - Pulp and Paper Waste:

Pulp and Paper Biomass Waste represents the cellulose residuals that are a waste byproduct of pulping operations and/or papermaking operations. The biomass waste was estimated using production values from *Lockwood-Post's Directory*, pulp and paper residual waste per ton of production data from the industry's *National Council for Air and Steam Improvement, (NCASI)* 1997 technical information, and the number of employees reported in the *1998 County Business* patterns. These calculations for estimating the multipliers and conversion factors are shown below in Appendix B.

Geographic Distribution - Landfill Tip Fees and Transportation Costs

Every landfill in the SERBEP region, which reported a tip fee in the Directory and Atlas of Solid Waste Disposal Facilities, was plotted onto a contour map of the region. Due to the size of the database, a diskette is provided separately that lists all of the landfill site data, including their respective tip fee charge when available. For the purposes of this analysis, waste hauling used truck transportation as the basis for delivery of the biomass waste. Truck transportation multipliers and conversion factors for cost estimates are provided in Appendix B.

Total Manure and Biomass Feedstock Available:

The total manure and biomass feedstock available for the Cowpens site was estimated based on landfill tipping fee cost offsets as an indication of sustainable disposal. To accomplish this, the net value of waste disposal services at a given straight line distance from Cowpens, SC was estimated. The distance was calculated between each of the landfill sites and the Cowpens site, and then used to calculate a 2-way transportation cost based on the transportation costs developed in Appendix B. Data sets from above were each plotted on contour charts. Using sophisticated interpolation techniques, the scattered county by county or landfill site data was then converted into a regular grid map covering the same area. This step allowed individual biomass generation sites to be assigned a local waste disposal tip fee. The developed transportation cost per mile was then subtracted from each of the generation site's interpolated landfill tip fee. Each point in the grid map was evaluated to see if it would be economically viable to haul biomass from that location. If that was the case the biomass generation amount was added into the total, and if it would not be profitable then it was not included.

Conceptual Engineering and Technical Review Methodology

The engineering work was based on the following conceptual engineering work, feasibility documents or technical evaluations provided by the project partners:

- Linpac Cogeneration Study #1.
- Linpac Cogeneration Study #2.

- Linpac and RRSI Tour and Technical Evaluation of CCI's Newmarket BTA Biogas Facility.
- CCI BTA Technology Conceptual Engineering and Cost Estimate Work.
- Linpac and RRSI Conceptual Engineering and Technical Evaluation Work.
- Linpac and RRSI Cogeneration Vendor Equipment and Specification Work.
- Linpac and RRSI Operational Cost Estimate and Capital Cost Estimate Work.

The CCI/BTA technology application for the Biomass/Cogen’s biogas facility has undergone a preliminary technical evaluation by Linpac and RRSI staff, with assistance from CCI's corporate management and Newmarket engineering and operational staff. The CCI/BTA technology and support systems were shown preliminarily to be technically feasible and viable based on the conceptual engineering and technical evaluation work efforts as defined below.

The conceptual engineering work and technical evaluation services (THE ENGINEERING) used to determine the preliminary technical feasibility and capital cost estimates of the project presented in this report are defined as follows, and are subject to the following assumptions and limitations:

- The objective of THE ENGINEERING services and deliverables is to define the necessary CCI/BTA process equipment and systems to allow Linpac to develop reasonable equipment capital cost estimates to plus or minus 20% of total Biomass/Cogen project equipment cost (excluding specialty installation costs, working capital needs, taxes, transportation, corporate costs and after contingency).

- The objective of THE ENGINEERING services and deliverables is to define the necessary building and facility support equipment and systems to allow Linpac to develop reasonable building and support facility equipment capital cost estimates to plus or minus 20% of total Biomass/Cogen project facility or support equipment cost (excluding specialty installation costs, working capital needs, taxes, transportation, corporate costs and after contingency). Preliminary cost estimates are provided for the basic building to provide rudimentary cost expectations for the building, and final costs are dependent on final preliminary design engineering and construction engineering requirements.

- THE ENGINEERING DID NOT provide complete preliminary design, detailed design engineering, construction engineering or specific process or value engineering. Conceptual engineering efforts and technical evaluation efforts were preliminary and rudimentary in nature and developed first in order to show the technology's capability and second to provide preliminary capital cost estimates.

- Should the project proceed to future implementation steps, Linpac and/or CCI will be required to make final design and equipment selections based on agreed upon performance guarantees and any final contract(s) that would develop or be negotiated between Linpac and CCI, or between Linpac and any other chosen equipment suppliers and/or vendors.

- Linpac and/or the Biomass/Cogen owner/operator will be required to perform all required preliminary design engineering, detail design engineering, process engineering, and value engineering to fully scope and define the project based on the final design and equipment selections, and to obtain exact quotations for project procurement efforts from all project supplier or vendors.

The conceptual engineering and technical evaluations provide the basis for THE ENGINEERING efforts. The project capital was calculated and related project workscope needs defined. Reasonable preliminary feasibility conclusions were made based on the result of THE ENGINEERING work and the associated estimates.

Conceptual Engineering and Technical Evaluation

The engineering workscope involved providing a conceptual view of the proposed Biomass/Cogen facility using the BTA technology as a basis. The engineering work identified major equipment and systems for the facility, with corresponding capital cost estimates. The CCI/BTA technology application for the Biomass/Cogen's biogas facility underwent a preliminary technical evaluation by Linpac and RRSI staff, with assistance from CCI's corporate management and Newmarket engineering and operational staff. The CCI/BTA technology and support systems were shown preliminarily to be technically feasible and viable based on the conceptual engineering and technical evaluation work efforts.

A preliminary review of the CCI/BTA technology was performed, including a plant tour and technical review of the unit operations at the CCI Newmarket, Canada biogas production facility. Based on this work, the targeted Biomass/Cogen facility size is a 165,000 tons per year biomass feedstock with solid/liquid raw material handling capability. It uses a two stage BTA anaerobic digestion including a hydrolysis step. There is a cogeneration option for steam and electricity production, capable of producing 4-5 MW electrical production or equivalent energy. The Biomass/Cogen facility conceptual engineering work developed four options for the boiler or cogeneration use of the biogas.

Anaerobic Digestion for Biogas Production

The facility intends to use CCI's BTA anaerobic digestion technology as the basis for the process. Based on CCI data, the literature search and available documentation including the other project partners' in-house materials, a general description of a typical anaerobic digestion process for biogas production can be provided as follows:

Anaerobic Digestion:

Anaerobic digestion is essentially microbial action on organic material in the absence of significant oxygen. In some cases, the goal is to reduce BOD/COD of wastewater. In others, including this project, the goal is to produce biogas containing 65% - 75% methane for use as natural gas fuel substitute.

Feedstock Materials:

A wide range of organic materials may be successfully processed in an anaerobic digester. Animal manure, animal parts and renderings, agricultural residuals, human fecal waste, food processing scraps, spoiled fruits and vegetables, plant and wood pulp, waste paper, even municipal solid waste (MSW) have all been used to generate biogas. Many of these biomass feedstocks currently represent environmental disposal problems with regard to watersheds and landfill considerations. The use of anaerobic digestion technology can provide a viable solution to waste problems while producing a valuable renewable energy.

Digestion Conditions:

Anaerobic digesters are typically operated at elevated temperatures to reduce digestion time, although a slow digestion is also possible at room temperature. The material to be digested is typically mixed in a slurry with low solids content, typically in the range of 0.5% to 10% solids by weight. Larger solid materials are typically broken up to increase surface area for digestion. Mesophilic bacteria operate optimally somewhere between 35 and 50C, while thermophilic bacteria operate best in the 60 to 75C range. Digesters may be operated in a single stage or a two stage fashion. In the two stage version, the feedstock consistency and operating temperature of the two stages are different from each other. The CCI process targeted for the facility will use a two stage process. While the digestion process depends on extremely complex interactions of many kinds of microbes and materials, operation of anaerobic digestion systems does not require detailed knowledge of these interactions. A fairly predictable outcome can be achieved by following basic principles of process flow, temperature control and feedstock quality monitoring.

Two or Three Stage Digestion Process:

Numerous varieties of bacteria and other microorganisms can exist and even flourish in an aerobic setting. The exact populations of particular species vary significantly with the material undergoing digestion, temperature, populations of other species and a number of other factors. Very roughly, the microbes can be classified into hydrolyzing, acid-forming and methane-forming varieties, with each type acting approximately in succession on starches and cellulose. The digestion succession is somewhat different in the cases of proteins and other materials, but typically there are two to three steps in the breakdown or digestion process, with different bacteria involved in different steps of the digestion.

Products Formed:

If the digestion process is allowed to approach completion, methane and carbon dioxide will typically be the predominant gases, along with smaller amounts of ammonia and hydrogen sulfide. The gas generated by biopower digesters typically contains 50-75% methane, with carbon dioxide making up most of the balance. The remaining solids will include bacterial cell matter as well as indigestible material suspended in water. These can be converted to a high quality compost.

Biogas Quality and Use:

In order to use the biogas for power generation, removal of excess moisture from the gas as well as scrubbing of any significant detrimental quantities of toxic hydrogen sulfide may be required. For some types of combustion, carbon dioxide percentage in the biogas may also need to be reduced from the biogas. The biogas is then suitable for use as fuel and as a viable replacement for Linpac's purchased natural gas or in green power production.

Project Design Criteria

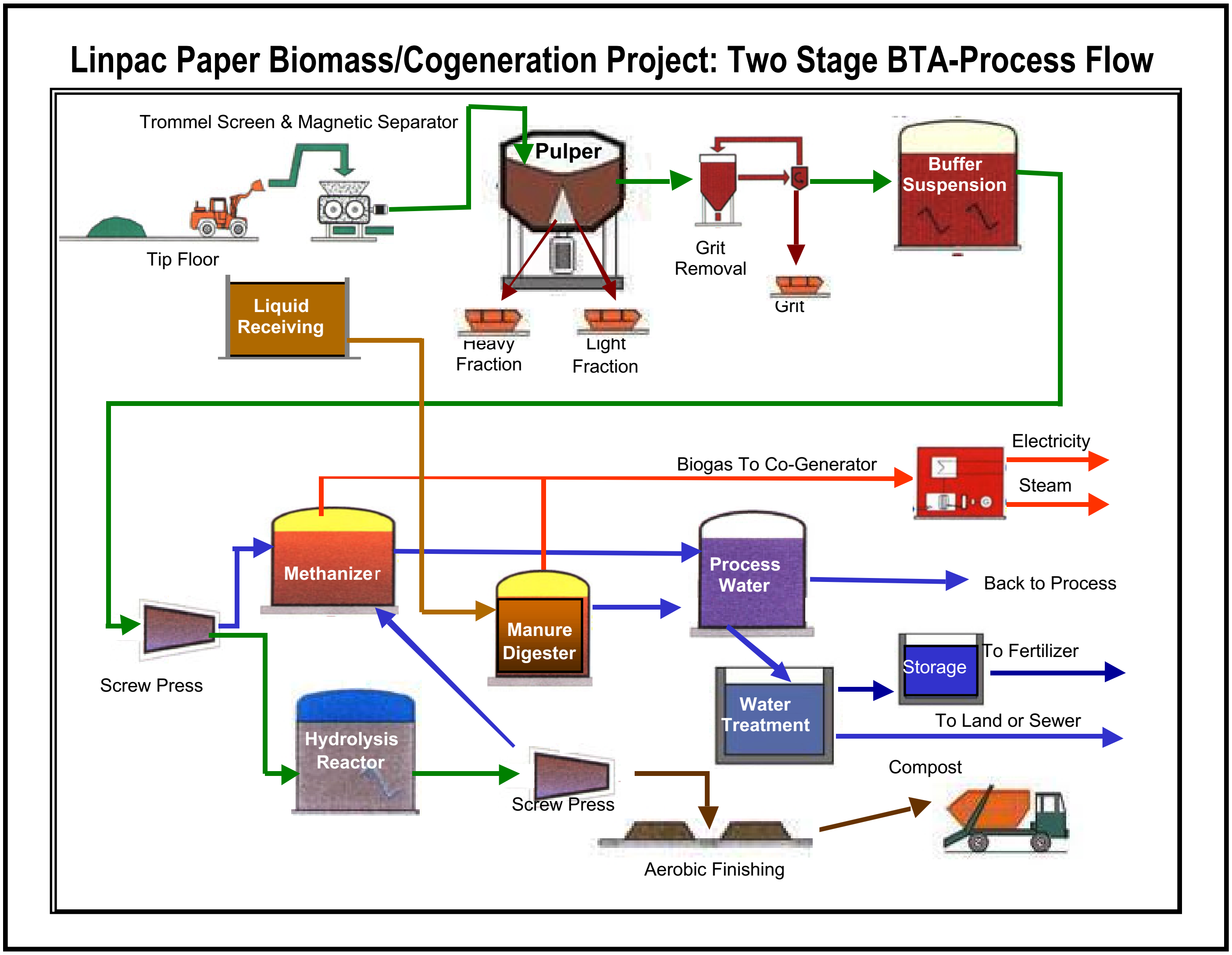
The conceptual engineering and technical evaluation work involved developing and generating preliminary conceptual design criteria, operational estimates and preliminary documents necessary to provide a preliminary capital cost estimate for the Biomass/Cogen facility. The target design criteria is a starting point based on the CCI facility operational parameters, which use similar feedstocks as are planned for the Linpac facility. The specific facility design operational inputs/outputs will be fully detailed in later project phases. Table 1 below provides the targeted Biomass/Cogen facility's basic design criteria targets.

Table 1: Facility Design Criteria and Input/Output Targets

Design Criteria	Target
INPUTS	
Plant Biomass Waste Tonnage Input	165,000
Percent Biomass Waste Input	91%
Percent Water Input	9%
Additives/Chemical Input	0.01%
OUTPUTS:	
Plant Energy Output	4 - 5 MW
Percent Biogas Output	10%
Percent Compost Output	35%
Percent Organic Water Output	39%
Percent Light Fraction Reject Output	11%
Percent Heavy Fraction Reject Output	2%
Percent Grit Output	3%
Percent Ferrous Output	1%

Based on the conceptual engineering and technical evaluation work performed, the target size of the Biomass/Cogen facility was established as per the above design criteria in Table 1. This size is based on what is known about the impact of scale learned from CCI. The CCI Newmarket facility size parameter is similar to the one listed above, and this size is believed to be a prudent template for design. Future facility expansions can occur after facility operations and market conditions allow. The design criteria for the boiler and cogeneration options was based around four potential options for the biogas use in energy production, which are described later in this report.

Figure 1: Biomass Cogen Process Flow Diagram



Appendix C provides the conceptual engineering and technical documents. These include the process flow diagrams (PFD) for the expected Biomass/Cogen facility, with a PFD for the CCI/BTA anaerobic digestion technology, PFD's for the cogeneration options, and support equipment vendor PFD documents, schedules and estimates. Conceptual engineering results, technology evaluations and descriptions follow below.

CCI/BTA Anaerobic Digestion Technology

The CCI/BTA anaerobic digestion technology is the key technology component of the Biomass/Cogen facility. The facility will use the BTA process, a German technology that separates the waste and uses anaerobic digestion to generate biogas in an "in-vessel" odor controlled facility. The technology was developed in the 1980's by Biotechnische Abfallverwertung GmbH (BTA) of Munich, Germany. Commercial BTA plants operate in Europe and Canada. The CCI/BTA anaerobic processing facilities footprints are typically compact facilities. Since the BTA process is all contained within pipe work and vessels, and since the design included using a biofilter for facility exhaust air streams, the facilities are environmentally friendly. Odors do not have the potential to develop and escape during the process.

The CCI/BTA technology provides for excellent production rates of biogas from a range of animal manure and biomass feedstocks. The BTA technology unit operations can be consolidated and considered in three major processing components: pre-processing/pre-sorting; BTA technology anaerobic digestion; and compost residual solids treatment. These major processing components are performed using the unit operations shown in the PFD provided in Appendix C. The moisture content of the incoming organic waste stream can range from 90 percent down to 50 percent; therefore, selection of the type of organic wastes received at the facility will need to be monitored to minimize the addition of process water and maximize the amount of waste processed. The operating flexibility in the BTA process allows the system to accommodate these ranges of input and maintain processing capacity. This flexibility is an important feature because waste based raw material streams frequently vary in composition and thus have caused many processing technologies to under perform their expectations.

Preprocessing starts when organic feedstock materials delivered by collection vehicles are offloaded. Liquid materials such as animal manures, waste milk/beverages, or slurries are pumped into storage tanks. Solid materials are offloaded on the tipping floor, then loaded onto a conveyor and sent to the presort station, where oversized and unacceptable materials are removed. After the pre-sort station, the material continues through a trommel screen with two screens sized to separate fine materials (mostly organic), medium sized materials (mostly containers) and large materials such as cardboard, film, plastic and textiles. The front end of the screen is equipped with a series of knives to open plastic bags. Medium and large materials can be both manually and mechanically sorted to remove recyclables and residues. Recyclable material is baled and sent to appropriate markets, and unusable residue is removed and taken for disposal. The remaining organic rich material is ready for the next step.

The BTA anaerobic digestion technology begins with the hydropulper. Organic rich waste is fed to a large capacity hydropulper and mixed with water (or liquid waste). The biomass waste is pulped with process water into a slurry with a solids content of eight to 16 percent. The hydropulper creates an organic pulp and removes contaminants. Hydropulpers have been routinely used for many years in the pulp and paper industry to pre-process wood pulps and therefore are well proven. This adaptation of the hydropulper equipment has been operated very successfully in BTA plants in Canada and Europe.

The BTA process incorporates hydropulping equipment with proven capability of mixing water with the biomass waste, as well as removing the non-organics. .The hydropulper also has raking equipment to remove the inorganic materials from the slurry. The major component of the non-organic materials separated by the rakes on the hydropulpers is plastic film. The plastic film can either be disposed of in a landfill site, sold for reprocessing, or reprocessed with the proper equipment on site for sale as recycled resin. Lightweight contaminants and non-organic materials, such as plastic missed in the presort separation process, are removed. Additionally, heavyweight non-organic materials from the slurry are removed. The materials expected to be present in the waste stream include metals, glass stones and bones. The pulping step is followed by a stage that removes sand and grit using a hydrocyclone. Hydrocyclones are commonly used in industry for removing solids from slurries. The slurry that is pumped to the hydrocyclones, to separate the inert grit and sand from the slurry, is a key step that caused some problems in the slurry pipe work and pumps in earlier facilities. These inert materials can be used in certain applications, such as asphalt or concrete, or will require disposal in a landfill site.

The remaining pulp is pumped to the anaerobic digester for decomposition into biogas and compost. Anaerobic digestion is a biological process that uses bacteria to break down solids without the presence of oxygen. Anaerobic digestion is where the slurry undergoes biological action to produce biogas, which is typically 65% - 75% methane. The digestion process takes days and results in two beneficial by-products: biogas and compost. In anaerobic digestion, the optimum conditions of the organics within the digestion process are approximately eight to 16 percent solids. Anaerobic digestion produces little exothermic energy and most of the energy is retained in the methane gas produced from the process. Anaerobic digestion systems, therefore, process the organics in a liquid slurry form. In typical anaerobic digestion processes, some slurries or sludges from a treatment facility can be very low in solids and may have to be dewatered prior to the digestion process. The use of liquid animal manures may require the same type of dewatering step, or the liquid manure can be used in combination with drier feedstock materials to obtain the proper mill process water balance. The biogas is fed to cogeneration units where it is used to produce electricity and heat/steam.

In the BTA technology process, the degritted slurry is pumped into suspension buffer tanks. These tanks provide storage capacity to even out the flow of waste materials delivered to the facility on a daily basis and to provide a uniform flow to the digestion process. Slurry from the buffer tanks is pumped to the anaerobic digestion process. Organics that are not suitable for the slurry undergo a separation step into an intermediate hydrolysis unit operation. This converts the organics and celluloses to digestible material suitable for methane production and re-entry into the digestion slurry. Digested sludge is pumped from the digestion tanks to centrifuges for dewatering. Centrifuges are used for dewatering sewage sludges and are common equipment in the sewage treatment industry. While these processes are individually proven and commonly used, working efficiently in an integrated system requires complex process control systems. BTA provides such computerized process control systems for the management of the process.

Waste biomass from the process slurry that is not converted to methane is removed from the process and converted to compost using aerobic methods during the solids treatment. The compost fraction is created from undigested waste organics. In aerobic composting processes, the waste processed is a solid with an optimum moisture content of between 50 to 60 percent. Aerobic composting processes require bulking agents to be mixed with the organics to aid in the distribution of air (oxygen) through the waste biomass so that aerobic bacteria can flourish. These bulking agents also assist in reducing the moisture content of the waste to optimum conditions. The capacity of the aerobic facility has to account for the addition of bulking agents. The type and amount of the bulking agents will depend on the type of waste biomass organics to be processed. Aerobic composting typically requires an additional 25 to 30 percent of bulking agents, which can increase the size of the facility composting area. The compost will be cured and distributed for soil amendment or land application use, horticultural use, and other uses depending on the regional needs and requirements.

CCI Newmarket Biogas Facility Review

The BTA technology has proven operating facilities in Canada and Europe. The waste stream processed at these facilities is for all practical purposes identical to that to be processed in the United States. Representatives of the Linpac team have visited the CCI Newmarket, Canada operating facility to review the technology. The purpose of the tour was to review the BTA technology based system during facility startup and full operation of the plant.

The CCI Newmarket facility is a $20 million (Canadian dollars) one-stage full-scale biogas plant that is fully operational and produces biogas used to generate electrical energy for the local utility. An approximately $7 - $10 million (Canadian dollars) second stage digestion expansion is planned. Linpac and RRSI engineering staff toured the CCI biogas generation plant in Newmarket, Ontario, Canada. Plant Executive Director John Brewster gave an initial overview of the facility. Then, Senior Process Control Operator Bill MacDonald led a walking tour of the plant and described various components of the methane generation process and material handling. Bill MacDonald was enthusiastic about the BTA technology used in the CCI Newmarket plant. Although their plant was in a startup phase, they said that current indications were that methane production and plant capacity would be significantly higher than expected.

Each of the major systems was observed and evaluated, and a description of each of the key unit operations shown in the PFD is given below. Appendix D provides corresponding facility tour photos of the CCI Newmarket plant. These document the CCI/BTA technology in operation, and aid in review of the BTA methane generation technology. The facility is clean with very minimal odor. The facility makes significant use of computer controls to operate, maintain and troubleshoot problems in each major component.

Raw Materials Tipping Floor

Organic waste materials are brought to the facility in covered trucks and tipped loose onto the receiving floor. The material is removed from a truck within 24 hours of its arrival and placed on the tipping floor.

The plant typically receives a few different types of organic wastes. At the time of our visit, for example, there was outdated produce in one pile on the tipping floor, and restaurant food waste with some packaging material in another pile. In order to maintain a steady “diet” for the methane generating bacteria, operators mix different kinds of waste into one of several recipes. The response of each recipe is tested and recorded. This performance information is used to refine the recipes to optimize plant performance.

Materials are either loaded directly onto a conveyor to the pulping system, or sent first to a trommel screen and sorting area for pre-processing. The trommel screen breaks plastic bags of commercial restaurant waste and prevents the largest materials from entering the pulper. Some recyclables are reclaimed from the trommel screen rejects. A variety of biomass organic feedstocks was and may be used, and some experimentation was ongoing and required to develop optimal “recipes” for maximum methane generation. For animal manure feedstocks, recipes will have to be developed, and it is likely the animal manure will be run in combination with some other biomass feedstock.

Pulping and Grit Removal and Pre-processing

A movable conveyor system directs materials from the tipping floor and trommel screen areas to one of three pulping units in the facility. Each pulper has a skimming unit to remove lightweight materials, such as plastic bags, remaining in the material mix. Water is added to the organic materials to aid in the pulping process. After pulping, the slurry is sent to a centrifuge separation system, which has three output streams. The light fraction is sent to a sorting process to remove plastic recyclables, with the remainder sent to landfill. In a similar fashion, the heavy fraction is sorted for metals, with the remainder used for road aggregate.

Methane Generation System

After pulping and grit removal, the remaining organic slurry is processed for methane production in the methanizer. Based on future design engineering and balances, the additional pulping or slurry capacity can allow for an additional methanizer unit operation, increasing biogas production. Insoluble organics are removed in a bank of screw presses. These insolubles would be further digested in a hydrolysis reactor during two-stage digestion, but during current single stage operation, these solids become residuals that are added to the compost. The liquid containing soluble organics is reduced to a low consistency. The pH is adjusted and the material is fed to the anaerobic digestion tank. Dissolved solids are reduced by this process and chemical oxygen demand (COD) is brought virtually to zero. Methane is collected at the top of the digestion tank and sent to the cogeneration system after water is removed from the gas.

Residuals Handling

From the process stream, solid organic materials remain after the soluble organics are removed (in single stage digestion, which is the current level of operation). These solids are readily compostable in an aerobic composting process. Currently, the uncomposted solids are sold or given away to a soil products company that carries out the needed composting before selling the material. Amendments such as sawdust are typically mixed with these solids for better drying and aeration during aerobic composting.

Liquid residual from the methane generation process is partially recycled back into the process water. The remainder is sent to sanitary sewer. It contains some dissolved solids, but has low biochemical oxygen demand (BOD) and chemical oxygen demand (COD). Although not currently done at Newmarket, some European facilities convert the liquid residuals into a liquid fertilizer for sale in agricultural and farm markets.

Plastics, metals and other non-digestible materials removed from the process stream in the trommel screen, hydropulper and grit removal system are processed further to recover recyclables. Magnetic and eddy current separators make possible the removal of metals from the residual stream. Glass and other heavy materials are recycled as road aggregate. Plastics are manually sorted. Non-recyclable solids from the process are sent to landfill. A system of chutes and bins is used to collect sorted materials for transport off site.

Biofilter

The entire facility has a negative pressure that prevents odors from escaping the plant. A large ventilation system in the tipping floor area pushes several air changes per hour through a biofilter system to minimize odors both inside and outside of the facility. The exhaust air passes through a mixture of wood bark and compost, which removes odor-causing compounds. As a result, the working air quality inside the building is quite good, with only mild detectable odors in the tipping floor area. Outside the plant, the odor is barely detectable. The Newmarket facility is located within a commercial and office park, where odor is not allowed or tolerated.

Cogeneration System

Two 1 Megawatt internal combustion engine and generator sets on site are available to produce electric power and heat for the plant, using biogas produced in the plant, and, when necessary, supplemental natural gas. At the time of our visit, the plant was in a startup phase, producing about 1 MW worth of biogas. During full single stage operation, they expected to produce about 2 MW worth of biogas. With two-stage digestion, to be implemented at a later time, the expected production was more than twice as high, or about 5 MW of power. The plant requires about 1 MW of power to operate. Any excess power generated on site may be sold to the local electric utility. The biogas can work with either existing boilers fitted for biogas flow requirements, or cogeneration equipment made to use biogas as the fuel.

Based on the CCI Newmarket plant tour and technology review, the visit to CCI's facility showed the BTA technology as viable and feasible for use as the anaerobic digestion biogas technology with the planned Biomass/Cogen facility.

Cogeneration Options

The Biomass/Cogen facility conceptual engineering work developed four options for the boiler or cogeneration use of the biogas. Option 1 involved retrofitting the existing mill boiler suitable for biogas use and adding biogas to the natural gas supply to generate steam. This steam would be used for mill steam requirements only. Options 2, 3 and 4 looked at various cogeneration units where the biogas was used as part of the fuel. These options are described below.

Option 1. Retrofit Existing Boiler. In this option, the existing boiler is retrofitted and converted to utilize biogas, or a mixture of biogas and natural gas, at existing capacity, producing steam at 225 psi, 450 F. Approximately 25-30% of the fuel would be supplied by the biogas facility. The cost of this option would only include tie-in piping costs from the biogas generation facility. The savings is the amount of gas displaced by biogas, namely 25% of current gas usage. Only steam for mill use is produced. No electricity is generated with this scenario. This option requires the lowest capital investment, because the cogeneration capital costs are minimal.

Option 2. Steam Turbine cogeneration system. High pressure 100,000 pph McBurney package boiler followed by a topping cycle Turbosteam turbine with exhaust at 225 psi, 450 F. If boiler output is at 650 psi, 700 F, the steam turbine output is 1.9 Mwatt at full capacity. Approximately 20-25% of the fuel used would be supplied by the biogas facility. The cost savings is a little more complicated. 7% more total fuel gas is used to obtain the same amount of steam as before, but 1.9 MW of electricity is generated at the same time. 20-25% of the natural gas would be replaced by biogas. The capital investment is higher than in Option one, but lower than in Options 3 or 4.

Option 3. Gas Reciprocating Engine for cogeneration. 2910 kWatt Waukesha Gas Engine with 3400 pph steam recovery at 225 psi, 400 F. The steam would supplement output from the existing boiler, reducing natural gas consumption by roughly 3-4%. 2.9 MW of electricity would be available for plant use or sale as “green energy.” This would reduce plant electricity costs by 20-25%. Capital investment for this option is higher than for Options 1 or 2, but less than in Option 4.

Option 4. Gas Combustion Turbine cogeneration system. Replace the existing boiler with a gas combustion turbine system, consisting of 2 Solar Taurus gas turbines and associated controls and piping. Fuel use would increase approximately 10%, but the system would produce virtually all of the electrical power needed by the Linpac plant. In our application, a portion of the natural gas fuel (approximately one-quarter to one-third) would be replaced by biogas. The operating cost savings would be sizable. The electric power bill would be essentially eliminated, while fuel usage would increase by 10%. 20-25% of the fuel could be replaced by biogas. To achieve these significant gains, more capital investment would be required for this option than for Options 1, 2 or 3.

Options 2, 3, and 4 above would install a new cogeneration unit that is conceptually sized to match with mill steam requirements, based on the total linerboard mill steam requirements. These options add the biogas to the natural gas supply necessary to run the cogeneration unit, supplying all mill steam, and some or all of the electrical needs. These options allow the mill to meet the target steam requirements for production while taking advantage of the biogas vs. natural gas substitution. The sizing of the cogeneration units also allows for any future biomass facility increased capacity and expansion phases, where biogas production would be increased by increasing the anaerobic digestion biogas component of the facility. The options allow any additional biogas production to be readily used by the mill for the natural gas substitution, without having to retrofit or enlarge the cogeneration units.

Project Capital Cost and Operational Cost Estimates

Based on the conceptual engineering work these equipment lists were developed and used to generate preliminary capital cost estimates for the four options. The project options are described with accompanying capital cost summaries as follows:

Capital Cost Estimates

Appendix E, F, G, and H provide the equipment list and preliminary capital cost estimates for options 1, 2, 3 and 4 respectively. Tables 2, 3, 4 and 5 provide summaries of the preliminary capital cost estimates for the four options.

Option 1. Retrofit Existing Boiler. In this option, the existing boiler is retrofitted and converted to be able to utilize biogas. This option would provide the biogas to the existing boiler, replacing approximately 1/3 of the existing natural gas purchases, and provide 100% of the linerboard mill's steam requirements. Table 2 provides the estimated capital cost summary for Option 1. The estimated capital cost of the Biomass/Cogen facility with this option is $26,206,481.

Table 2: Option 1 Capital Cost Summary*

Project Capital Item	Cost ($US)
Raw & Finished Materials Handling	$ 725,926
BTA Equipment	$ 7,988,889
Cogeneration Equipment	$ 398,148
Auxiliary Equipment	$ 555,556
Building Costs	$ 8,003,704
Engineering	$ 4,744,444
Startup	$ 1,407,407
Optional Equipment	$ 0
Project Contingency @ 10%	$ 2,382,407
Total Project Capital Costs	**$ 26,206,481**

**see Appendix E for optional equipment list and costs*

Option 2. Steam Turbine. Cogeneration system using a high pressure McBurney package boiler followed by topping cycle Turbosteam turbine. This option would provide the biogas to the new steam turbine unit, replacing approximately 1/3 of the natural gas. The steam turbine would provide 100% of the linerboard mill's steam requirements, while generating approximately 800 kW of electricity for use in the biogas facility. Table 3 provides the estimated capital cost summary for Option 2. The estimated capital cost of the Biomass/Cogen facility with this option is $29,940,981.

Table 3: Option 2 Capital Cost Summary*

Project Capital Item	Cost ($US)
Raw & Finished Materials Handling	$ 725,926
BTA Equipment	$ 7,988,889
Cogeneration Equipment	$ 3,793,148
Auxiliary Equipment	$ 555,556
Building Costs	$ 8,003,704
Engineering	$ 4,744,444
Startup	$ 1,407,407
Optional Equipment	$ 0
Project Contingency @ 10%	$ 2,721,907
Total Project Capital Costs	**$ 29,940,981**

**see Appendix F for equipment list and costs*

Option 3. Gas Reciprocating Engine. Cogeneration system using a Waukesha Gas Engine with steam recovery. This option would provide the biogas to the new gas reciprocating engine unit. The gas reciprocating engine would provide approximately 33 - 40% of the linerboard mill's electrical requirements, while generating no steam for the linerboard mill. Hot water would be generated for use in the biogas facility. Table 4 provides the estimated capital cost summary for Option 3. The estimated capital cost of the Biomass/Cogen facility with this option is $32,007,402.

Table 4: Option 3 Capital Cost Summary*

Project Capital Item	Cost ($US)
Raw & Finished Materials Handling	$ 725,926
BTA Equipment	$ 7,988,889
Cogeneration Equipment	$ 5,671,712
Auxiliary Equipment	$ 555,556
Building Costs	$ 8,003,704
Engineering	$ 4,744,444
Startup	$ 1,407,407
Optional Equipment	$ 0
Project Contingency @ 10%	$ 2,909,764
Total Project Capital Costs	**$ 32,007,402**

**see Appendix G for equipment list and costs*

Option 4. Gas Combustion Turbine. Cogeneration system with a gas combustion turbine system, consisting of 2 Solar Taurus gas turbines. This option would provide the biogas to the new gas combustion turbine unit, replacing approximately 1/3 of the natural gas. The gas combustion turbine would provide 100% of the linerboard mill's steam requirements, while generating 100% of the electricity requirements as well. The gas combustion turbine would also generate steam and electricity for use in the biogas facility. Table 5 provides the estimated capital cost summary for Option 4. The capital cost of the Biomass/Cogen facility with this option is $37,976,481.

Table 5: Option 4 Capital Cost Summary*

Project Capital Item	Cost ($US)
Raw & Finished Materials Handling	$ 725,926
BTA Equipment	$ 7,988,889
Cogeneration Equipment	$ 11,098,148
Auxiliary Equipment	$ 555,556
Building Costs	$ 8,003,704
Engineering	$ 4,744,444
Startup	$ 1,407,407
Optional Equipment	$ -
Project Contingency @ 10%	$ 3,452,407
Total Project Capital Costs	**$ 37,976,481**

**see Appendix H for equipment list and costs*

The capital cost estimates above represent reasonable preliminary cost estimates that are representative of each scenario's project costs, and can be used in determining and assessing the preliminary expectation of project feasibility and viability for each of the facility choices.

Optional Equipment

The capital cost lists show a line for "optional equipment", which has been zeroed out for the purposes of the preliminary capital cost estimates. These optional equipment items are presented because the eventual Biomass/Cogen facility could take advantage of optional equipment to either increase the biomass feedstock grades or types of materials that can be used, or provide value added conversion to some of the facility's residuals or waste by-products. This could include:

- Eddy Current Separator - can be used to separate waste materials into components, increasing the sales price or value in the appropriate recycled market.
- Magnetic Separator - can be used to separate ferrous materials out of residuals and wastes.
- MRF Sort Line - manned stations can sort high value materials out, such as newspaper or sorted papers from the input side, or aluminum cans and other high value items from the output side.
- Thermal Vessel Processing - can be used to break down non source separated wastes, MSW or other composite wastes to more efficiently remove the biomass component.
- Alternate Fuel Pelletizers - can be used to pelletize residuals including waste cellulose and/or polyethylene materials to produce an alternate fuel for sale as a stoker boiler coal substitute.
- Continuous Batch Washers - can be used to wash fiber or plastic residuals or byproduct to provide a cleaner, more high quality material, increasing the sales price of the recycled material.
- Resin Pelletizers - can be used to pelletize plastic residuals to provide recycled resin pellets for sale to the plastic lumber or composite industry, increasing the facility revenue.
- Fluff Dryer - can be used to dry cellulose or plastic materials to decrease moisture content for shipping savings or for quality improvements that can increase the sales price of the materials.
- Roll-off or Liquid Tanker Truck - can be used to provide owner controlled transportation of feedstocks, using roll-offs for solid and tanker for liquid, to procure high volume sources.

The above optional equipment choices will have to be evaluated for their benefit individually or in combination. Some of the evaluation work can be done using vendor pilot facilities.

Operational Cost Estimates

Preliminary operational cost estimates for some key parameters are provided in Appendix I, based on each of the previous section's described options and CCI provided data on the Newmarket, Canada biogas facility. These operational costs do not represent the complete operational costs the plants may incur, as they are conceptual views of some key parameters. Detailed operational costs were developed based on the specific Linpac plant requirements and supplier or vendor information for chemicals, etc. Some preliminary operational cost estimates were developed based on the CCI Newmarket facility operational factors and their expected application in the Cowpens regional area. The facility should be energy self-sufficient, saving some purchased operational costs. Table 6 below provides preliminary cost estimates for key operational cost areas that potentially apply for a Biomass/Cogen facility.

Table 6: Some Key Preliminary Operational Cost Estimates

Operating Cost Area	Cost ($ per Input Ton)
Plant Staffing	$8.00 - $10.00
Fresh Water	$0.10 - $0.20
Waste Water	$0.15 - $0.20
Solid Waste (w/o market recycling)	$4.00 - $4.25
Process Equipment Maintenance	$2.75 - $3.00
Electrical Maintenance	$0.80 - $1.00
Building/Property Maintenance	$0.15 - $0.25
Handling Equipment Maintenance	$0.25 - $0.30
Biofilter Maintenance	$0.15 - $0.25
Chemicals (defoamer/flocculents/agents)	$2.50 - $3.00
Plant Operating Fee	$1.20 - $1.25
Plant Operating Contingency Funds	$1.10 - $1.50

The preliminary operational cost estimates shown are reasonable estimates that do not appear to add detrimental cost areas to the operations and negatively affect the mill's operational cost structure.

Facility Permitting Requirements

The major regulations pertaining to construction, air, water, land and waste permitting have been reviewed, along with some additional requirements. Facilities designed to utilize agricultural and organic wastes to produce biogas, and use this biogas to generate steam and electricity, would require appropriate permits for construction and operation. While significant effort is required to acquire the permits for locations in Cherokee County or Spartanburg County, South Carolina, there appear to be no inordinately large hurdles to permit these facilities. It will be important to begin the permitting process early, because some of the permits require 180 days or more from application to issue.

South Carolina State Regulatory Framework

Like most states, South Carolina has implemented the federal Clean Air Act and Clean Water Act with state-specific versions. Air permitting is carried out through S.C. Code of Laws (COL) Title 48 and Code of Regulations (COR) 61-62. Water permitting is carried out via S. C. COR Title 61-9. These aspects are treated in detail in the subsections COR 61-9.504 on industrial sludge and COR 61-9.505 on land application. Solid residuals are regulated as solid waste under COR 61-107.

Disposition of Liquid Residuals:

The choice of feedstocks, and their associated moisture, can have a significant effect on the water balance in the facility. The CCI/BTA process strips most organic loading from the process water and typically has low heavy metal or contaminant loading. Inorganic dissolved solids can be concentrated in the process for removal and disposition, potentially allowing for closed loop zero effluent operations in the Biomass/Cogen facility. This liquid residual material has found value in European operations as a valuable liquid fertilizer. Land application of liquid residuals appears to be treated primarily through the water quality regulations, as materials applied to land potentially could leach toxic components (if they are present) into the groundwater. The facility's liquid fertilizer product should be compared against other liquid fertilizer product offerings to determine the necessary standards and permit requirements. A federal NDPES permit may be required for land application or septage of liquid residuals, which may be applicable to the liquid fertilizer from the CCI/BTA process. In the case of land application, COR 61-9.504 and 505 would be in force, with limits on heavy metals and pathogens. If sewer is available at the plant location, the liquid residual may be discharged without an NDPES permit, if it falls within acceptable limits for biochemical oxygen demand, toxic substances, and the like. Currently, CCI Newmarket discharges residual liquid to sewer without special permits, despite rather stringent requirements for effluent. If sewer is not available and the feedstock mixture's moisture content results in a overloading of water, an effluent treatment facility may be required as part of the plant. This would require a formal NDPES permit for the facility for discharging into a waterway.

Disposition of Solid Residuals:

With appropriate feedstocks for the biogas plant, the solid organic residuals from the anaerobic digestion process will be suitable, with some additional preparation, for resale as a soil amendment or compost product(s). After anaerobic digestion (or "composting") has been completed, the dewatered solids are typically combined with some sort of organic drying and bulking agent (e.g., sawdust) and aerobically composted for a short period of time. If this material is considered as an "industrial sludge," the dewatered residual from an industrial process, the South Carolina water pollution regulations for disposition of industrial sludge indicate that the composted material would be dealt with under regulations for solid waste:

61-9.504.4 Relationship to other regulations.
(b) The disposal of industrial sludge involving the composting or co-composting of the industrial sludge with yard trash, land-clearing debris, or a combination of yard trash and land clearing debris shall comply with the requirements established by the Department in R.61-107.4 [Solid Waste Management: Yard Trash and Land-Clearing Debris; and Composting]. *The submission and information requirements shall be determined by the Department.*

(c) The disposal of industrial sludge utilizing an innovative and experimental solid waste management technology or process shall be permitted under R.61-107.10. [Solid Waste Management: Research, Development and Demonstration Permitting].

> South Carolina Code of Regulations Section 61-107 specify how solid waste is to be handled and disposed of. Other solid plant residuals such as plastic, glass, metals, aluminum, sand and grit can be moved into existing recycled material markets as raw materials.

Cogeneration Facility Operation:

Air permitting appears to be the most important hurdle in biogas power generation. Under S.C. Code of Regulations 61-62, there are eight air quality standards that may apply to facilities. In the case of a biogas cogeneration system of less than 20 megawatts located in a lightly polluted area such as Cowpens, at least two standards are applicable. Standard 1 governs fuel burning operations. In particular, smoke from stacks must have minimal opacity, limited particulates and sulfur dioxide. Standard 8 governs toxic air pollutant emissions for any facility that emits more than 1000 lbs per month of a toxic pollutant. Given the clean burning nature and low toxic contents of biogas, these air quality standards should pose only small hurdles.

Piping of biogas is regulated by the federal Office of Pipeline Safety (Dept. of Transportation), if the pipes leave the property of the biogas plant or cogeneration facility.

Safety would be overseen by the South Carolina Office of Safety and Health Administration, which implements the federal OSHA standards with minimal changes.

Construction of Biogas and Cogeneration Facilities:

In addition to meeting state permitting requirements for environmental protection of air and water, building permits will be required for construction of a biogas or power generation facility. Land use permits are typically issued at the county or municipal level. The project is large enough that a public hearing for proposed land use would likely be required. Building permits would require following standard building codes for structures, electrical, plumbing and mechanical installations.

Sale of Electrical Energy:

In 1978, the federal Public Utilities and Regulatory Policies Act (PURPA) was passed to encourage development of cogeneration and renewable energy sources. South Carolina has not formally implemented PURPA in its regulatory structure, but has accommodated it through the existing structures. If a facility meets requirements for a Qualifying Facility (by meeting size, ownership, efficiency and/or energy source criteria), it gains certain beneficial guarantees of pricing and purchase from public utilities. Pricing agreements between seller and utility are approved by the Public Service Commission, Utilities Department. The actual benefits of Qualifying Facility status depend on how details and definitions in PURPA have been understood in precedent-setting cases.

Compost Product Standards Evaluation and Use Requirements:

Compost generated from solid residuals of the biogas generation process are the most likely to be subject to product standards. South Carolina and adjoining states have compost quality standards roughly equivalent to those given under the federal sewage sludge rule 40 CFR 503. “Class A” compost meets the 503 regulation limits for heavy metals and pathogens and limits the amount of manmade inert material. Compost which meets these standards is eligible for distribution and land application with very few restrictions. It may be sold in bulk or in bags. In the case of “Class B” compost, limits for contaminants, especially pathogens, are somewhat relaxed. In turn, this lower quality compost is allowed limited uses, typically only for non-agricultural applications where likely human contact is somewhat limited.

Current production of solid residuals at CCI Newmarket appears to have low contaminant levels that would meet Class A type compost standards in South Carolina, Georgia or North Carolina. The quality may be high enough to meet stricter requirements in states such as Michigan, which has developed contaminant limits based on leaching availability of the toxic material from soil into water as well as other potential paths to human ingestion. However, the state of Mississippi currently has such restrictive standards for compost that CCI residuals will probably not meet them. Further pilot test data will be required on this issue, but the prospects are promising for a highly marketable compost product.

Regional States Compost Regulatory Framework:

Composting standards vary significantly among SERBEP states and other states in the southeastern U.S.. A partial list of compost standards for several states in the southeast is given in Appendix J. Of those states listed, Mississippi has by far the strictest standards for compost products, with restrictions on metals content that may be below actual soil background levels and difficult to attain. Most other states roughly follow the federal guidelines for solids to be land applied, with a few exceptions (e.g., Tennessee is more restrictive, while Alabama and Washington, D.C. appear to have no requirements of their own). Most states require compost product testing at intervals of three to six months. Typically, labels that describe appropriate use of the compost as well as amounts of nutrients and toxic constituents are required.

Adjoining states Georgia and North Carolina appear to have regulatory frameworks similar to that of South Carolina, with state-specific implementations of the Clean Air Act and Clean Water Act, and some kind of solid waste management regulation which includes compost. Compost products sold in these states would need to be permitted, requiring information about the source of the material as well as initial and periodic analyses of the nutrients, pathogens and contaminants in the products. Transport of feedstock materials may be regulated if they are “putrescible.”

In North Carolina, the Department of Environment and Natural Resources (DENR) has a Division of Air Quality, a Division of Water Quality and a Division of Waste Management. The DENR's regulations contain a section on Solid Waste Compost Facilities (Section .1400 of DENR regulations). The facilities are divided into four classes, depending on the feedstocks. Type 1 is for garden and wood waste. Pre-consumer, meat-free food waste comes under the Type 2 heading. Type 3 waste includes manure and other agricultural waste, as well as post-consumer source-separated food waste. Type 4 waste is mixed municipal solid waste.

The compost products are classified by quality, based on a scheme roughly equivalent to the Federal 40 CFR 503 standard for land application of sludge. Class A compost is unrestricted in its uses, and has stricter quality requirements. First, it requires some kind of process to reduce pathogens to an acceptable level. Second, the level of man-made inert materials may not exceed 6% by dry weight. Finally, the material must have metals content below the 40 CFR 503 standard levels.

It is important to note that Section .1402 of the regulations specifies the same quality requirements for compost imported from outside the state as it does for compost manufactured within North Carolina. Testing requirements, for one sample per six months or every 20,000 tons of product, hold in the case of imported as well as in-state products. In addition, detailed labels are required on compost products sold in bags.

In Georgia, under the Department of Natural Resources, Environmental Division, there are regulations for Air Quality Control (391-3-1), Water Quality Control (391-3-6) and Solid Waste Management (391-3-4). The compost regulations give a somewhat looser description of requirements under 391-3-4.16 than for "North Carolina or South Carolina. Compost must be "non pathogenic," "free of offensive odors," biologically and chemically stable," "free of injurious components or particles," and "sustain plant growth." Presumably this applies to imported compost products as well as in-state products.

Georgia also requires a permit for vehicles transporting garbage and "putrescible wastes." If feedstock materials for a biogas plant are transported in Georgia, this requirement will apply.

Effects of Industry Standards on Compost:

Probably the most significant effect of industry standards will be the restrictions for contaminants in solid residuals to be marketed as Class A compost. The choice of feedstocks will heavily influence the quality of the solid residuals. Operation of the CCI/BTA process will also affect the solid residual product quality, particularly with regard to chemical/biological stability and pathogen levels. Careful control of this process will result in a stable product which reliably meets standards for high quality compost. A stable product will be required to assure both permitting agencies and potential customers of product usefulness and safety.

In development of a raw material basis, a balance will need to be found between feedstocks of known, stable quality, such as forest residuals and animal manures, and less understood feedstocks, or those of poorer quality that are less understood per their effect on residuals contamination. CCI Newmarket employs an ongoing supplier training program providing quality standards for feedstock acceptance and rejection criteria. This type of program is highly recommended for the new Biomass/Cogen facility to prevent contamination problems for the compost product. It is better for the facility to start with more homogenous feedstock such as animal manure, food processing waste, and agricultural waste. Once feedstocks from poorer quality streams, such as MSW based biomass streams or industrial streams, can be shown as safe for use they can be incorporated into the raw material procurement effort.

Site Specific Permitting Considerations

Site Development & Land Use Classification in Spartanburg County:

The existing Linpac paper mill is located in Cherokee County just outside the city limits of Cowpens. There are virtually no zoning restrictions in unincorporated Cherokee County, according to Jim Inman, Executive Director of the Cherokee County Development Board (Tel 864-489-5721. Also see Appendix J for other contact information). Building plans must be reviewed for conformity to the 1997 Standard Building Codes. At least two weeks will be required for a review of plans.

For sites in the city of Cowpens, the general application is processed by Spartansburg County, which passes on the land use request to the town clerk of Cowpens (Shirley Reynolds, Tel. 864-463-3201). The town planning commission conducts any necessary public hearings and responds to the zoning request. If there is no request for zoning change, the town planning commission apparently has only the role of review, with the county providing primary oversight.

In unincorporated Spartanburg County, South Carolina, site development and land use are reviewed under a "Unified Land Management Ordinance Permit." In major projects (a 160,000 ton biogas plant qualifies as a "major project"), a public hearing is required before approval of any development plan. After the public hearing, the permit is usually processed in about three weeks.

Facility Construction:

In Cherokee County, the chief building inspector is Mike Doles (Tel. (864) 487-2561). Building and environmental plans are reviewed and building permits are issued through his office. The plans are evaluated according to the 1997 Standard Building Codes and 13 NFPA fire protection codes. The fee schedule in Appendix J of the 1997 Standard Building Codes is followed for building permits. The application process is described in Appendix J of this report.

Appendix J outlines several steps that must be followed to obtain a commercial building permit in the County of Spartansburg (both Cowpens and unincorporated Spartansburg). It includes submission of site and building plans for review, a sewer permit and a site development application. For questions, contact Spartanburg County. Call (864) 596-2728 for general information. For technical questions related to building codes, contact Laurie Bailey at (864) 596-3173. Until July 1, 2001, the 1997 versions of the Standard Building Codes (also Structural, Mechanical and Plumbing) and the 1999 version of the National Electrical Code are in effect for Cowpens and unincorporated Spartanburg County. After July 1, 2001, The 2000 International Building Codes will be in effect. (This information is from Mike Padget, Tel. (864) 596-3182.)

According to Mike McGrath of Spartanburg County Environmental Services, Tel. (864) 596-3584, the state Department of Health and Environmental Control directly handles environmental permitting for the town of Cowpens. In unincorporated Spartanburg County, permitting is handled by the county Environmental Services. Sam Kokely of the Spartanburg Sewer District was given as a good contact for this. Environmental Services reviews the grading plan for stormwater handling and looks at the project for compliance with state and local environmental regulations. It then sends approval to Spartanburg County Building Codes Department, which actually issues the building permit. In Cherokee County, environmental permitting would be handled through the Building Inspections and Code Enforcement Department.

Safety in Operation:

Worker and public safety is of paramount importance. South Carolina OSHA safety regulations must be followed in both biogas facility and cogeneration facility, as in other workplaces. Where work hazards exist, appropriate protective equipment and procedures must be implemented, and warnings must be posted to alert personnel to hazards. Proper procedures for emergency response should be prepared and posted. If the biogas generation facility is permitted as a Solid Waste Processing Facility, it will be subject to regulations in S. Carolina Code of Regulations (S.C. COR) 61-107.6F. Other regulations may also apply.

Raw Materials Permitting:

Commercial farms would be required to change their waste handling permit to include transport and "disposal" at a waste processing facility such as the potential biogas plant. (COR 61-43.100.30, 61-43.200.30) The Waste Processing Facility permit required for the biogas plant may also have written into it commercial farms from which it anticipates receiving animal waste, as well as businesses and organizations from which it expects other kinds of waste approved by the permit. A procedure would be required for dealing with waste that arrives at the facility and is not allowed under the Solid Waste Processing Facility permit issued by DHEC.

Transportation of raw materials to the site should follow Dept. of Transportation guidelines. In all cases, spillage of materials from transport vehicles must be avoided. Odors emitted from the vehicle should be minimized by covering or enclosing the material. Incoming material should be removed from transport vehicles within 24 hours of arrival at the facility.

Special attention should be paid to keeping all organic materials inside the facility to avoid mixing with stormwater. The tipping floor must be cleaned regularly. If a NPDES permit is issued for the facility, it will most likely require monitoring of the stormwater system for presence of materials from the biogas facility, and a plan for preventing spillage of materials into the stormwater system.

Solid Waste Facility Site Assignment and Operating Permit:

The biogas facility is expected to process a large quantity of materials that would be considered solid waste if they were not processed by the facility. As mentioned in Section 2.1, commercial agricultural facilities must acquire a solid waste permit for handling of manure and other organic materials. Since such materials are part of the input to the biogas generation facility, it is possible that the facility will be considered a "Solid Waste Facility" by regulating officials. It is also possible that the facility will fall under the categories of "Materials Recovery Facility" or "Recovered Materials Processing Facility."

If the facility is considered to be a "Solid Waste Facility," it will be required to follow regulations and permitting requirements in S. Carolina Code of Regulations 61-107.6. The permit application, which must be signed by an engineer licensed in South Carolina, must include:

• An engineering report including descriptions of the site, facility, processes and equipment, types and quantities of waste to be processed, as well as a list of disposal or recycling facilities which will receive the processed waste.
• Complete construction plans and specifications.
• A personnel training program.
• Identification of possible paths of pollution by the facility.
• A waste control plan, including procedures for dealing with waste not allowed by the permit.
• A contingency plan during periods of non-operation.

Air Pollution Control Permitting:

The biogas generation plant is expected to pose very little air pollution problem. With the exception of the tipping floor, all of the material processing is carried out in enclosed, airtight vessels. Air from the tipping floor area is ventilated through a biofilter, which removes most of the organic odor-causing compounds both inside and outside of the facility. Composting pathogens are contained in the enclosed methane generation tank, and materials are pasteurized before and after the methane generation process. As a result pathogen levels in the air are expected to be low and similar to background levels. This leaves only the gaseous product of the process, biogas, which contains 60-80% methane, 20-40% carbon dioxide and trace amounts of hydrogen sulfide. Hydrogen sulfide is a toxic gas, and its level in the biogas should be monitored, because it could enter the air as a product of combustion in the cogeneration facility, or as the possible result of the unlikely event of a biogas leak. Operating experience at the CCI Newmarket plant suggests that levels of hydrogen sulfide in the biogas are typically well below dangerous levels, on the order of 50 ppm in the gas.

The main requirements related to air pollution control permitting are described in S. Carolina Code of Regulations section 61-62.

One of the eight standards given in S.C. COR 61-62 which may apply to a biogas generation facility is Standard 8. Standard 8 (given in S.C. COR 61-62.5) requires a permit for facilities which emit more than 1000 lbs/month of any toxic air pollutant. For amounts less than this, a permit may or may not be required. The list of maximum allowable concentrations of specific toxic pollutants are given in Appendix J. Hydrogen sulfide is the only major known toxic substance in the biogas. Assuming projected production of biogas for a 160,000 ton organic waste processing facility and biogas composition similar to biogas produced in European BTA plants, the hydrogen sulfide is expected to be on the order of 100 lbs per month, about a tenth of the trigger level for mandatory air permitting. Since biogas is not expected to be released into the air, the hydrogen sulfide is only expected to be released if some sort of leak occurs in the facility, or when the biogas is burned in the cogeneration facility. See Section 3.2 for further consideration of air quality permitting connected with the cogeneration facility.

Permit Requirements for Liquid Residuals and Wastewater:

Options for dealing with wastewater and liquid residuals include 1) discharge to the Spartanburg County sewer system with a county sewer permit; 2) land application with a DHEC land application permit, and 3) discharge to surface waters with a NPDES permit. These options are described in greater detail below.

Discharge to Public Sewer System:

The first option for discharge of liquid residuals and wastewater is discharge to the public sewer within constraints of sewer operating authority. In and near the Town of Cowpens, this authority is the Spartanburg County Water System. The county currently operates a sewage treatment plant with a 1.5 million gallons per day (1.5 MGD) capacity, with 300,000 gallons per day currently utilized. An industrial facility must obtain a Spartanburg County Water System sewer permit in order to discharge into the sewer system. For further information, contact John Holcomb (Tel. 864-582-3250).

The permit application requires information about the average quantity of water discharged, basic parameters of the wastewater such as biochemical oxygen demand (BOD), total suspended solids (TSS) and pH, as well as information about possible toxic materials that may appear in the wastewater. The permit will include standard constraints, given below, as well as additional constraints on problem materials expected in the wastewater. Problem materials would include heavy metals and toxic organics.

Standard constraints on wastewater are as follows: pH must be between 6 and 8.5, though special arrangement can be made for water with pH higher than this range. The basic limit on BOD is 250 mg/l, with surcharges of $16.74 per 100 lbs BOD for greater amounts, with the concentration in no case exceeding 2000 mg/l. Likewise, the basic limit on TSS is 300 mg/l, with surcharges of $15.05 per 100 lbs TSS for greater amounts, and the concentration of TSS in no case exceeding 2000 mg/l. Oil and grease content in the wastewater must be less than 100 ppm, with no exceptions. For wastewater flows greater than 52 gpm or 75,000 gpd, there is a flow equalization requirement, such that the wastewater flow is constant 24 hours per day, 7 days per week.

Land Application:

A second option for disposal of liquid residuals from the biogas facility is application of these residuals to land. In this case, liquid residuals are sprayed or in some fashion spread on land as irrigation and fertilizer. The South Carolina DHEC regulates land application through a land application permit, which is roughly analogous in content to the NPDES permit, except that wastewater contact is eventually with groundwater rather than surface water.

It may be possible to market liquid residuals from the biogas plant as liquid fertilizer via a land application permit. It is possible that eventual users of the residuals would need to be registered in the land application permit. The details of this option remain to be investigated further.

To obtain a land application permit, an application package including information prescribed in S.C. COR61-9.505.21 must be submitted to DHEC. Information required includes name and location of the facility, a description of the industrial process, expected amounts and quality of wastewater to be discharged, and a plan for how the wastewater will be land applied. Maps must be included to show topography near the site. Any hazardous substances which may be in the wastewater must be described, and plans for groundwater monitoring (if applicable) must be included.

Discharge to Surface Waters:

A third option for disposing of liquid residuals from the biogas plant is discharge into a stream or other surface water near the facility. A NPDES permit is required for this disposal option. For further information, contact Melinda Vickers at DHEC Bureau of Water (Tel. 803-898-4186).

The requirements to obtain a NPDES permit are in S.C. COR61-9.122. Included in the requirements are information about the nature of the industrial activity; quantity of wastewater to be discharged; a basic water mass balance for the industrial process, including any treatment carried out on site; amount of "sludge" generated from the process and its disposal method, and other information as described in the regulation. The application must be submitted at least 180 days before discharges are to begin, although applicants are encouraged to leave more time to ensure a timely issue of permit.

The NPDES would require monitoring of wastewater flows and particular contaminants defined in the permit. Toxic materials which may be expected in the wastewater will likely require monitoring, as may pathogen levels.

Permit Requirements for Stormwater.

Any industrial facility located in or near Cowpens will require a NPDES permit for stormwater, separate from any permit for wastewater disposal from the biogas facility. Contact Harvey Daniel (803-898-4033) of DHEC's Bureau of Water for further information on stormwater permitting.

The NPDES permit application for a new industrial facility must be submitted at least 180 days before commencement of the project. The application should include standard Forms 1, 2D and 2F. In addition, a topographical site map, drainage structure drawings, pollution reduction measures for the facility and an estimate of impervious land area should be included. Other information may also be required. Regulations for stormwater permitting are described in S.C. COR 61-9.122.26. NPDES Forms 1 and 2F for stormwater permitting are included in Appendix J.

Biogas Plant Operator Certification:

Some operators in the biogas plant may be required to obtain state certification if their duties fall into regulated categories. Part or all of the biogas plant may be designated as a Wastewater Treatment Plant (WWTP). Operators whose duties include operation of the designated WWTP equipment must be certified at the level required to run that equipment. Certification is carried out through the S.C. Dept. of

Labor, Licensing and Regulation, Environmental Certification Board. Information on classes of WWTP operator (physical and biochemical) and certification regulations can be found at the board's website:

http://www.llr.state.sc.us/POL/Environmental/Default.htm.

Second, part or all of the biogas generation facility may be designated as a Solid Waste Processing Facility. While no special certification is required under this designation, the following guidance is offered by state regulations:

61-107.6.I. Personnel Training Requirements [for Solid Waste Processing Facilities].
Solid waste processing facility personnel training programs shall, at a minimum:
1. [Reserved]
2. identify the positions which will require training and a knowledge of the procedures, equipment, and processes at the facility;
3. describe how facility personnel will be trained to perform their duties in a way that ensures the facility's compliance with the regulations, including the proper procedures that shall be followed in the processing and handling of solid waste not authorized by the Department to be received at the facility; and,
4. be designed to ensure that facility personnel are able to respond effectively to emergencies by familiarizing them with emergency and safety equipment, emergency procedures and emergency systems.

If the biogas and cogeneration facilities are located at different sites, most of the permit requirements must be met separately for the two facilities. If the two operations are located on the same site, some additional permits will be required for the cogen capability beyond those permit requirements for the biogas facility described in Section 2. Some of the permit requirements discussed in Section 2 will apply to the cogeneration facility as well, corresponding to the construction, operation and material waste streams of that facility. Additional permit requirements for the cogeneration facility are given in this section.

Fuel Transport & Pipeline Safety Permitting:

If the biogas and cogeneration facilities are at different locations, a pipeline will be required to transport biogas to the cogeneration plant. Transport of flammable gas is governed by the federal and state departments of transportation.

Pipeline safety certification would be accomplished through the South Carolina Public Service Commission, Utilities Department, Pipeline Safety Section. They would evaluate the pipeline plan for compliance with federal standards and regulations. These regulations are given for the most part at the Federal Office of Pipeline Safety website, *ops.dot.gov*. In particular, CFR Title 49, Chapter 1, Part 192 gives detailed guidelines for pipeline materials, construction, control, testing, inspection, operation and maintenance.

Air Pollution Control Construction & Operating Permits:

The cogeneration facility is potentially subject to at least two air quality standards as given in S. Carolina Code of Regulations (COR)61-62.5. As with the biogas generation facility (see Section 2.3), the cogeneration facility may require a permit under Standard 8: Hazardous Air Pollutants. A list of hazardous air pollutants with their concentration limits in air is given in Appendix J. If any of the listed pollutants is emitted at a rate of more than 1000 lbs. per month, a permit is mandatory. If emissions are lower than this, a permit may or may not be issued at the discretion of DHEC.

The cogeneration facility is also subject to Standard 1: Emissions from Fuel-Burning Operations. This standard places limits on opacity, particulate content and sulfur dioxide content for exhaust stack emissions. It prescribes monitoring procedures and protocols by which it can be assessed whether the Standard is being met. These restrictions on emissions vary somewhat with the location of the facility. In particular, if the facility is located in a heavily populated industrial area, the allowable emissions, especially for sulfur dioxide, are smaller. All of Spartanburg County is in the least restrictive class of locations in South Carolina, because of its low population density and relatively high ambient air quality. With attention to proper operation of the boiler, gas turbine or engine which runs utilizes the biogas, pollution control measures required to comply with Standard 8 will be minimal.

Wastewater Permitting:

The cogeneration facility is expected to generate only minimal wastewater associated mainly with cleaning of facilities and employee restrooms. On occasion the facility may discharge heating system water. A sewer permit with Spartanburg Sanitary Sewer District should provide the necessary services for this type of wastewater handling. An application form for a sewer permit is given in Appendix J. The biggest issue will be how a large discharge, such as flushing of the cogen heating system water, is handled, so that the sewer district does not get a large slug flow from the cogen facility which disrupts the operation of the wastewater treatment plant. If the cogen and biogas facilities are permitted as a single unit, the wastewater from the biogas system will most likely hold the largest influence over which method(s) of wastewater disposal is (are) chosen. See also section 2.4 of this document, on biogas facility liquid residuals and wastewater permitting.

Stormwater Permitting:

A stormwater system for an industrial facility requires a NPDES permit, issued by S. Carolina Department of Health and Environmental Control (DHEC). If the biogas system and cogen facility are co-located on the same site, a single stormwater permit would most likely be developed for both facilities. If the cogen facility is located on site at Linpac, stormwater permitting may be achieved through a modification of the existing facility permit. See also Section 2.5 of this document, on stormwater permitting for the biogas facility. Some relevant NPDES permit application forms are included in Appendix J.

Sale of Electricity to Utilities:

S.C. PSC Utilities Department would approve energy price rates agreed on between facility and utility. Beyond this, the department is not involved with an electrical generation facility smaller than 75 megawatts.

Under the Public Utilities Regulatory Policies Act of 1978 and The National Energy Policy Act of 1992 (EPACT) the federal government authorizes states to develop competition in the utilities marketplace. Guaranteed markets and special pricing for power from renewable energy and are treated in this legislation. Utilities are required to purchase electricity from Qualifying Facilities at a price equivalent to their avoided cost for generating power themselves. South Carolina has not adopted electricity market restructuring legislation yet, so the precise impact of these federal acts is not clear.

Some tax incentives and cash subsidies for generators of renewable energy may be available from the U.S. Dept. of Energy as a result of the Energy Policy Act of 1992 through the Renewable Energy Production Incentive (REPI). These apply only if the plant begins operations by September 2003.

Cogeneration Facility Operator Permits:

Unlike in some states, S. Carolina appears to have no boiler operator certification program. Minimum training standards should be developed for operators to ensure safe operation of all power generation facilities.

Alternative Siting and Permitting Scenarios

While a great number of potential locations for a biogas/cogen plant exist, the connection of the outputs from these facilities to a particular paper mill restricts locations to those near that mill. The high cost of gas transport through pipelines or other means precludes sites which are more than a few miles away. This leaves three basic siting and permitting scenarios, all of which are very similar in terms of the permitting process.

On site at Linpac, some of the permits, such as stormwater, may be tied in with the existing paper mill through a modification of the existing permit. The new liquid and solid residuals streams would undoubtedly still require their own permitting process. The Linpac land use assignment would likely remain unchanged.

In Cowpens, a land use classification that allows construction and operation of a biogas/cogen facility would be needed. A public hearing may be required in the town if a change in land use from current classification is proposed. Permits other than the land use permit will be obtained through Spartanburg County or state DHEC, as described in earlier sections.

In Spartanburg County, outside of Cowpens, land use is overseen by a county board. A public hearing at the county level may be required. All other permits will be obtained through Spartanburg County or state DHEC, as described in earlier sections.

While the permitting process will not differ greatly anywhere in Spartanburg County, some sites may have particular features which will play a role in shaping the permits. For example, solid waste and wastewater operations are required to maintain certain buffer zones between the facility and residences, surface waters, etc. A site must be chosen which meets these buffer criteria. Geographical features may influence design choices, such as how to dispose of wastewater.

Feedstock Generation Survey

Feedstock generation survey results, represented by a range of estimates for specific organic waste streams and the animal manure and biomass feedstock totals, are described in this section. From this feedstock generation estimate data, specific organic streams and geographical areas can be targeted as being most appropriate for procurement use by the facility. The feedstock generation survey targeted the following animal manure and related biomass feedstock types:

- Animal Manure, represented by hog, poultry and cattle fecal biomass materials
- Animal Residuals, represented by slaughterhouse residuals and biomass waste
- Food Manufacturing represented by food processing facility biomass waste
- Food Service, represented by hotels, restaurants, grocery stores, etc., biomass waste
- Pulp and Paper, represented by mill cellulose fiber residuals and biomass waste

These animal manure and biomass sources and sectors were selected primarily because their waste streams reflect a high percentage of compostable organic biomass material suitable for use with the CCI/BTA technology. These materials are presumably available. Estimates were made based on the feedstock generation survey's analytical methods, and the resource management experience used to evaluate them. Generally, where data was available to support analysis and estimates, the feedstock generation estimates and results provided figures based on the following regional areas or parameters:

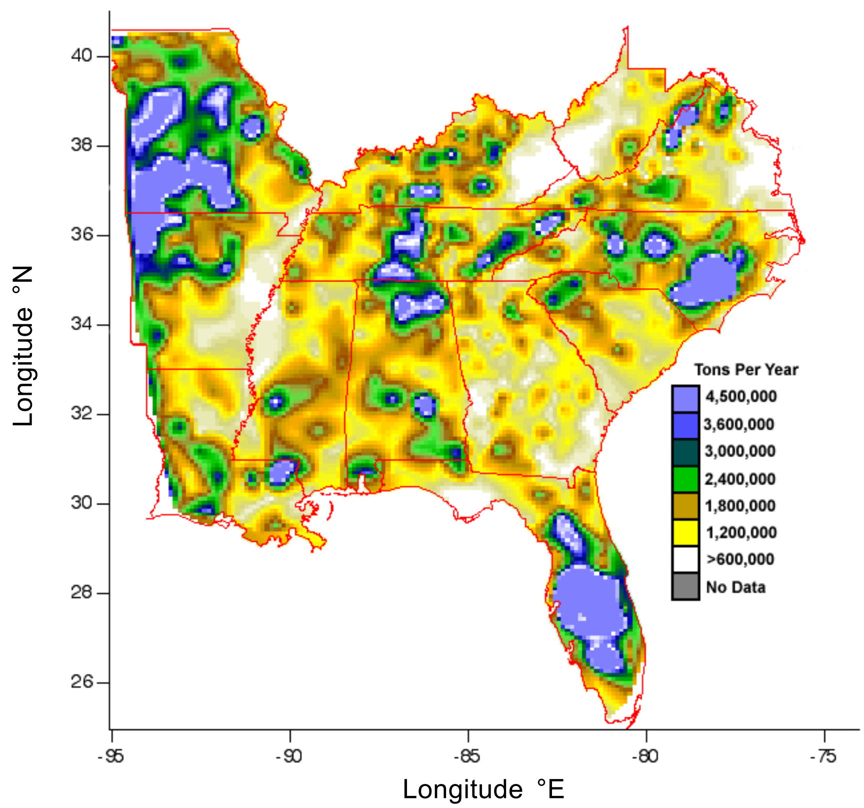
- State of South Carolina.
- Adjoining SERBEP States (South Carolina with North Carolina, Tennessee, Georgia).
- SERBEP States (all continental SERBEP States).
- All SERBEP States within a radius of 300, 600, or 900 miles of Cowpens, SC.
- All States (SERBEP and non SERBEP) within a radius of 300, 600, or 900 miles of Cowpens, SC.
- Top 25 in SERBEP region by biomass type.

These regional categories provided for feedstock estimates that were most applicable to the goals of the feasibility project and future facility operations. The feedstock generation estimates and results for each biomass type and regional category are provided in table form in this summary report, with applicable manure and biomass feedstock density mapping for the SERBEP regions provided in the appendices. It should be remembered that the feedstock generation estimated quantities represent a reasonable survey methodology for estimating what is a dynamic situation. Changes in agricultural or industrial production, increased regulatory and/or market pressures, and new options for beneficial re-use can change the assumptions. Future work demands attention to the manure and organic biomass waste re-use and/ or disposal practices and appropriately developed long term procurement strategies and programs.

Animal Manure

The Animal Manure biomass waste stream is by far the largest biomass stream per actual generation estimate amounts and dominates the biomass tonnage amounts with regard to the other biomass feedstocks targeted. The Animal Manure feedstock estimates developed with the previous section's outlined methodology have three animal components consisting of hog, poultry and cattle. Figure 2 provides feedstock density mapping for total animal manure.

Figure 2: Total Animal Manure



The concentration or density of a manure in a particular region is a result of the animal raising and production techniques used. In areas where Concentrated Area Feedlot Operations exist, the Animal Manure generation and density is great. In areas where open pastures or range is used, the density is reduced. Although Animal Manure is currently expected to have a very low percentage recovery rate, the overwhelming amount generated allows for even low recovery rates to provide more than enough feedstock material for the Biomass/Cogen facility. The areas of high density still represent the most opportunity for cost effective recovery. Figures 3a, 3b, and 3c provides the feedstock density mapping for animal manure by individual animal type.

Figure 3a: Hog Manure

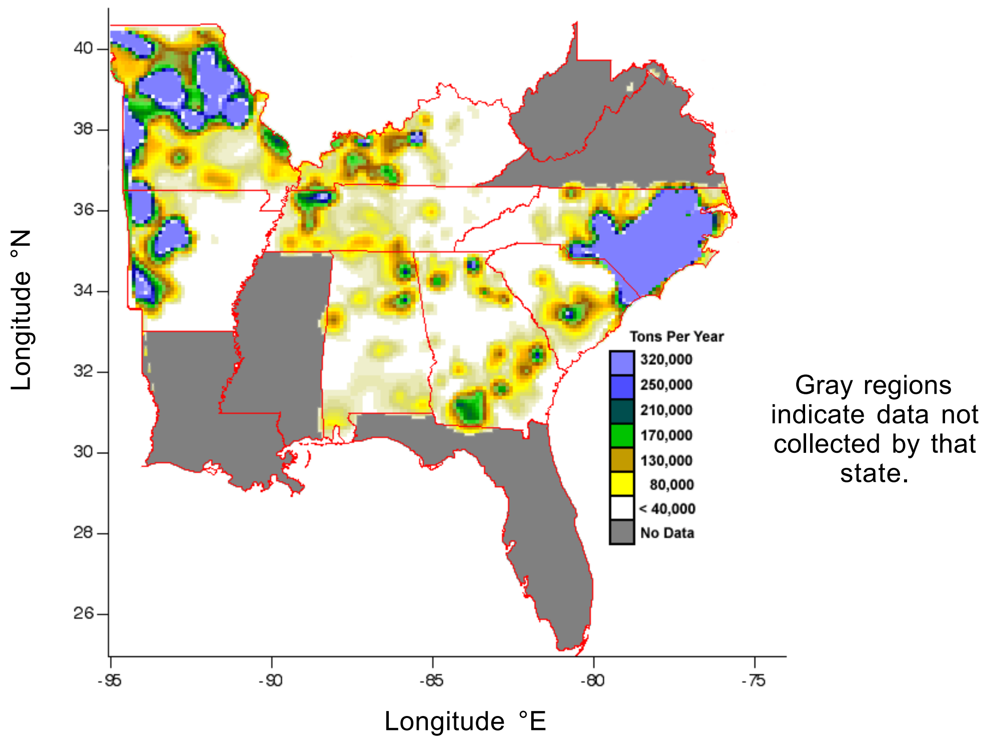


Figure 3b: Cow Manure

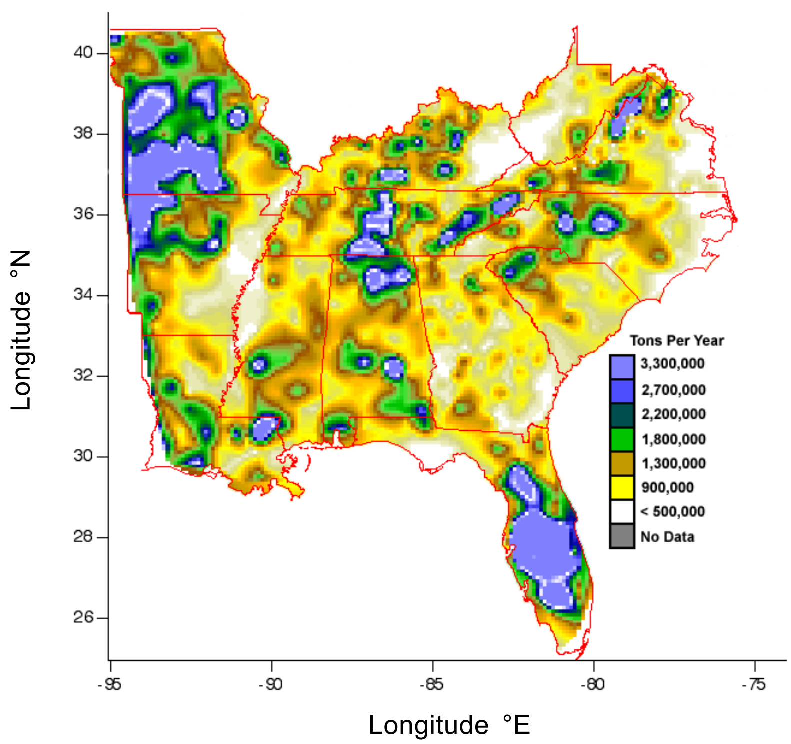
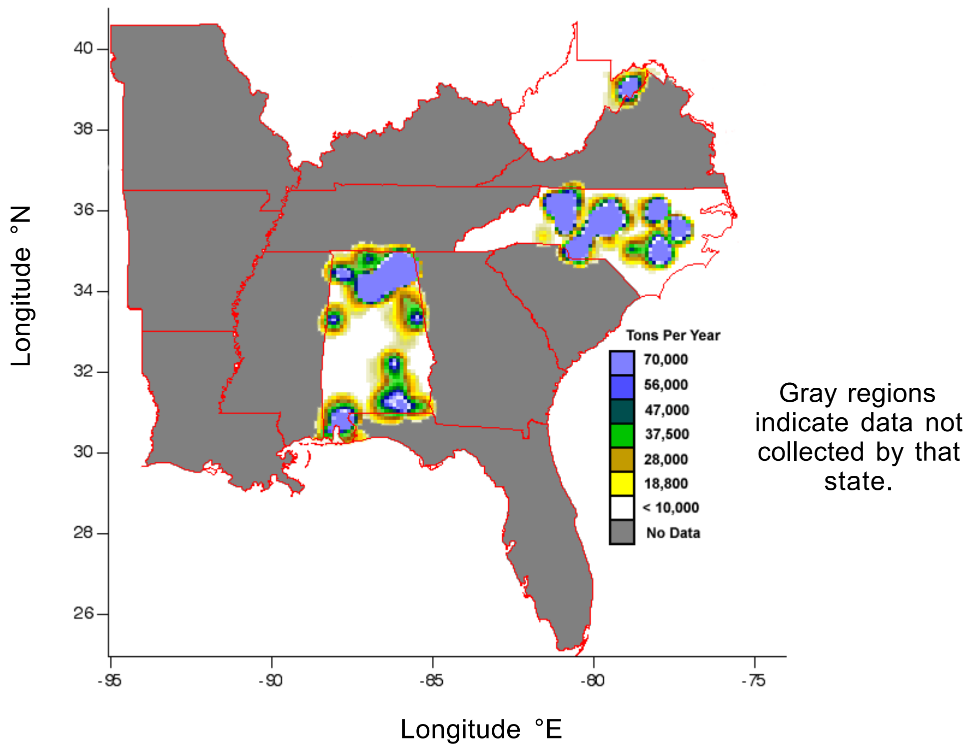


Figure 3c: Chicken Manure



The density maps show that hog manure is very concentrated in certain areas, (one of which is North Carolina as expected), that poultry manure is also very concentrated, and cattle manure is more distributed. Table 7 provides the regional Animal Manure feedstocks estimated as generated by animal type. Appendix K provides feedstock estimates for non SERBEP states for Animal Manure feedstocks by type, where data is available.

Table 7: Regional Animal Manure Generation Estimates by Animal Type

Region	Hogs Tons/year	Cattle Tons/year	Chickens Tons/year
South Carolina	1,419,412	30,275,277	No Data
Adjoining SERBEP States	95,888,420	279,613,506	3,238,886
All SERBEP	125,436,338	1,103,311,926	6,392,484
SERBEP States Within 300 Miles	20,523,074	184,039,913	2,290,421
SERBEP States Within 600 Miles	98,896,458	536,383,056	6,040,474
SERBEP States Within 900 Miles	102,391,406	742,065,863	6,392,484
All States Within 300 miles	20,523,074	199,201,831	2,290,421
All States Within 600 Miles	103,328,142	615,236,919	6,040,474
All States Within 900 Miles	159,990,012	1,169,364,374	13,614,149

Table 8 provides the total Animal Manure feedstock estimated as generated in the applicable regions.

Table 8: Regional Total Animal Manure Generation Estimates

Region	Total Animal Manure Tons/year
South Carolina	31,694,689
Adjoining SERBEP States	378,740,812
All SERBEP	1,235,140,748
SERBEP States Within 300 Miles	206,853,408
SERBEP States Within 600 Miles	641,319,989
SERBEP States Within 900 Miles	850,849,753
All States Within 300 miles	222,015,325
All States Within 600 Miles	724,605,535
All States Within 900 Miles	1,342,968,534

Table 9 provides the top 25 Animal Manure counties in the SERBEP region. North Carolina has many counties that are high on the list due to the concentration of hog production in the state. Cattle production appears to be the leading manure generation reason for the other counties in the list.

Table 9: Top 25 Animal Manure County Estimates in SERBEP Region

State Name	County Name	Hog Manure Tons/year	Cattle Manure Tons/Year	Chicken Manure Tons/Year	Total Manure Tons/Year	Total Biomass Tons/Year
N. Carolina	Duplin	28,908,000	1,605,380	175,912	30,689,291	30,693,899
N. Carolina	Sampson	13,446,600	862,148	33,817	14,342,566	14,344,205
Florida	Polk	0	12,238,541	0	12,238,541	12,287,809
Arkansas	Washington	1,226,400	10,900,725	0	12,127,125	12,144,874
Arkansas	Benton	1,248,300	10,256,591	0	11,504,891	11,511,336
Virginia	Rockingham	0	9,671,916	0	9,671,916	9,675,161
Missouri	Greene	32,120	8,884,091	0	8,916,211	8,929,835
Florida	Hillsborough	0	8,760,219	0	8,760,219	8,819,456
Virginia	Augusta	0	7,630,508	0	7,630,508	7,635,117
N. Carolina	Wayne	6,622,560	872,058	57,086	7,551,704	7,561,161
Missouri	Lawrence	40,880	7,075,562	0	7,116,442	7,117,337
Florida	Hendry	0	6,936,825	0	6,936,825	6,940,758
Florida	Osceola	0	6,798,089	0	6,798,089	6,811,722
Louisiana	Tangipahoa	0	6,342,240	0	6,342,240	6,351,126
Tennessee	Greene	0	6,183,684	0	6,183,684	6,185,277
Florida	Okeechobee	0	6,144,045	0	6,144,045	6,145,289
N. Carolina	Iredell	45,990	5,351,265	474,683	5,871,938	5,876,987
Missouri	Barry	44,968	5,826,933	0	5,871,901	5,873,260
Missouri	Franklin	843,150	5,014,334	0	5,857,484	5,859,427
Florida	Highlands	0	5,797,204	0	5,797,204	5,801,747
Missouri	Jasper	232,870	5,450,363	0	5,683,233	5,690,207
Alabama	Montgomery	0	5,559,370	72,692	5,632,061	5,645,934
Missouri	Howell	87,600	5,470,182	0	5,557,782	5,558,878
Florida	Manatee	0	5,390,904	0	5,390,904	5,429,802
N. Carolina	Robeson	4,664,700	722,421	0	5,387,121	5,404,061

Animal Residuals

The Animal Residuals are represented by hog, poultry and cattle residuals from slaughterhouses and meat processing facilities. Slaughterhouse and meat processing represents a very large volume of potential biomass feedstock materials since as much as 50%-70% of a typical animal is left over as "residual" material. Material can consist of offgrade meat, meat scraps, slaughter processing wastes, water treatment residuals, offal, skins, tallow, bones, animal hair, blood, rendering waste, cattle switches, hides, animal fat and paunch. The vast majority of this is already re-used as a raw material to make animal and pet feeds. The defined Animal Residual biomass used in this Task 3 Report is a minor amount of the waste "sludge" resulting from the slaughterhouse water treatment clarification process. This material is not typically desirable for use in the animal feed or rendering applications because of contamination or concern about "freshness". Table 10 below provides the Animal Residual estimates by SERBEP State.

Table 10: SERBEP Animal Residual Estimates by State

State	Hog Residuals tons/year	Cattle Residuals tons/year	Chicken Residuals tons/year	Total Residuals tons/year
Alabama	141	34	112	288
Arkansas	566	36	224	825
Florida	64	44	69	177
Georgia	498	28	183	710
Kentucky	426	51	14	491
Louisiana	29	20	15	63
Mississippi	120	27	90	236
Missouri	2,100	85	38	2,223
North Carolina	4,078	21	129	4,227
South Carolina	203	9	30	242
Tennessee	305	49	14	368
Virginia	590	28	65	684
West Virginia	17	9	21	47
Total	9,138	441	1,002	10,581

The material defined in this study is a very small percentage of the entire animal residuals, and is typically the small but problematic component of this biomass waste. However, it is worth noting that the Animal Residuals could become available via new regulations on their re-use, for instance to control "mad cow disease" and other re-use cross contamination problems. The slaughterhouse animal residual future factors could result in significantly more of the residuals becoming available, likely by an order of magnitude, and become a very large feedstock volume if even some of the currently re-used slaughterhouse residuals and wastes were affected. Table 11 below provides the Animal Residual totals by applicable region.

Table 11: Animal Residual Estimates by Region

Region	Animal Residuals Tons/Year
South Carolina	242
Adjoining SERBEP States	5,547
All SERBEP	10,581
SERBEP States Within 300 Miles	3,758
SERBEP States Within 600 Miles	6,740
SERBEP States Within 900 Miles	7,644

Table 12 provides the top 25 Animal Residual counties in the SERBEP region. North Carolina and Missouri are highly represented due to their hog slaughtering activity.

Table 12: Top 25 Animal Residual County Estimates

State Name	County Name	Animal Residuals Tons/Year	Total Biomass Tons/Year
North Carolina	Bladen	517	4,307,011
North Carolina	Wilkes	517	2,924,768
North Carolina	Chatham	270	2,837,577
Missouri	Barry	244	5,873,260
North Carolina	Sampson	241	14,344,205
North Carolina	Wayne	241	7,561,161
North Carolina	Union	241	2,186,562
North Carolina	Hoke	241	616,264
North Carolina	Bertie	241	379,503
North Carolina	Lee	241	353,561
Missouri	Greene	231	8,929,835
Missouri	Jasper	231	5,690,207
Missouri	Pettis	231	3,741,370
Missouri	Mcdonald	231	2,930,631
Missouri	Sullivan	231	1,001,214
North Carolina	Duplin	191	30,693,899
Virginia	Rockingham	163	9,675,161
Virginia	Isle Of Wight	129	164,256
Virginia	Accomack	129	52,710
Kentucky	Jefferson	119	774,080
Kentucky	Henderson	115	1,014,885
North Carolina	Lenoir	103	4,029,763
North Carolina	Surry	103	1,876,600
North Carolina	Wake	103	1,313,649
North Carolina	Richmond	103	749,185

Food Manufacture

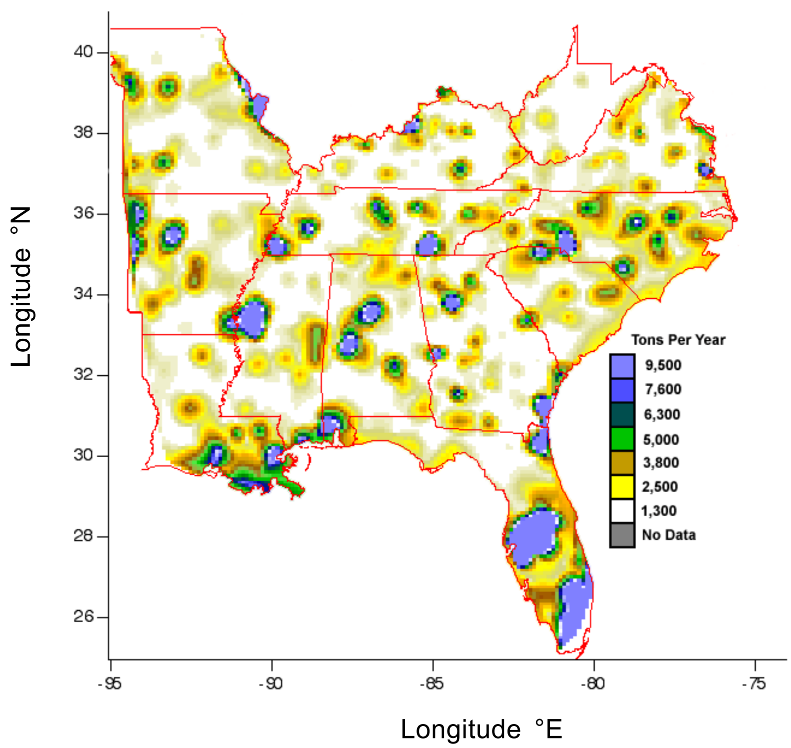
A significant organic waste stream comes from the food manufacturing and processing industry. The SERBEP region is a large generator of Food Manufacturing biomass wastes. The fruit and vegetable industries alone process million of tons of fruits & vegetables annually, a practice that generates a considerable volume of biomass waste in the form of pulp and rinds. Other Food Manufacturing industries also contribute significant volumes of biomass materials from residuals or rejected product. These materials are heavily laden with starches and cellulose which is a premium feedstock for CCI/BTA's anaerobic digestion process. Table 13 gives examples of some industries, and shows what this material consists of, along with the competitive forces for its disposition and/or re-use.

Table 13: Food Processing Waste by Type

Sector	Processing Wastes Description	Disposition
Dairy Industry	Dairy processing wastes, out of spec product, whey, milk sour, scrap cheese, suspended solids	Animal feed, composting, landfilling
Fruit & Vegetable Industry	Peels, off-grade vegetables and fruits, excess foliage, stems, skins, husks, cobs, pomace, liquid wastes, vegetable fat and oil, spice waste	Citrus pulp to animal feed; molasses, flavoring; vegetative waste to animal feed, stockpile or landfilling
Grain Industries and Bakeries	Brewery wastes, beer loss, flour wastes, milling scraps, wet corn, spent yeast, spoiled and spent grains, soybeans, out of spec bread, yeast, waste dough	Animal feed, landfilling
Sugar, Candy, Chocolate	Bagasse, syrup, molasses residuals	Bagasse burned for fuel or refined into industrial alcohol (furfural), landfilling
Mixed and Other Food Industries	Variable industries, but target industries include coffee products, drink bases, flavorings, food seasonings, snack foods, meals for airlines	Landfilling, composting, and various alternative re-use

Food Manufacturing density mapping is provided in Figure 4. The density mapping shows that this biomass waste is typically concentrated around the Food Manufacturing processing or industrial sites.

Figure 4: Food Manufacturing Waste



Food Manufacturing poses a disposal problem for certain landfills and other alternative methods, but is considered a valuable feedstock for the Biomass/Cogen facility. Table 14 summarizes estimated Food Manufacturing biomass waste generation by industry sector for the SERBEP region.

Table 14: SERBEP Food Manufacture Estimates by Industry

Industry Sector/Region	South Carolina	Adjoining SERBEP States	All SERBEP States	SERBEP Within 300 miles	SERBEP Within 600 miles	SERBEP Within 900 miles
Animal Food Manufacture Tons/Year	1,028	26,247	69,146	14,670	39,212	51,378
Starch And Vegetable Fats And Oils Tons/Year	345	8,959	16,950	3,306	7,701	13,968
Sugar And Confectionery Tons/Year	4,752	45,198	109,196	16,556	55,362	69,358
Fruit & Vegetable Preserving Tons/Year	18,465	81,702	268,534	52,158	108,368	209,438
Dairy Product Manufacture Tons/Year	674	4,838	16,518	3,182	9,029	12,104
Seafood Manufacture Tons/Year	1,000	46,450	327,900	1,500	114,975	261,900
Bakeries Tons/Year	11,827	194,827	389,317	111,647	275,309	329,037
Other Food Manufacture Tons/Year	3,300	41,925	119,489	23,050	65,382	88,943
Beverage Manufacture Tons/Year	4,575	64,781	190,054	47,655	116,847	158,991
Totals Tons/Year	45,965	514,927	1,507,104	273,724	792,184	1,195,117

The figures developed used conservative conversion factors developed from known industrial sites and processors, who work to reduce waste with industrial efficiency, pre-processing or other residuals reduction methods. Table 15 summarizes estimated Food Manufacturing biomass waste generation by industry sector for the areas represented by All States, or those States within the SERBEP regions combined with those States within a 900 mile radius from Cowpens in Non SERBEP regions.

Table 15: All States Food Manufacture Estimates by Industry

Industry Sector/Region	All States Within 300 miles	All States Within 600 Miles	All States Within 900 Miles
Animal Food Manufacture Tons/Year	14,670	45,005	100,953
Starch, Vegetable Fats, Oils Tons/Year	3,306	10,953	32,714
Sugar And Confectionery Tons/Year	16,556	59,378	187,971
Fruit&Vegetable Preserving Tons/Year	52,158	142,292	448,707
Dairy Product Manufacture Tons/Year	3,182	11,581	30,759
Seafood Product Prep. Tons/Year	1,500	115,225	330,225
Bakeries Tons/Year	111,647	314,196	618,357
Other Food Manufacture Tons/Year	23,050	78,017	191,240
Beverage Manufacture Tons/Year	47,655	146,760	286,844
Totals Tons/Year	273,724	923,408	2,227,768

Quantifying Food Manufacturing biomass waste generation by these sectors involves evaluating the quantity of raw material produced. However, industry experts estimate that between 10-30% of raw material inputs become waste during food processing. This number is likely much higher for certain products such as juice. Also note that not all food that is grown is highly processed (i.e. apples, oranges, vegetables, etc. that are sold directly for eating) but may still have a high reject rate "at the farm or distributor" that is not accounted for in these calculations. Table 16 provides a summary of the total Food Manufacturing biomass feedstock generation estimates by the applicable region.

Table 16: Food Manufacturing Estimates by Region

Region	Food Manufacture Tons/year
South Carolina	45,965
Adjoining SERBEP States	514,927
All SERBEP	1,507,104
SERBEP States Within 300 Miles	273,724
SERBEP States Within 600 Miles	792,184
SERBEP States Within 900 Miles	1,195,117
All States Within 300 miles	273,724
All States Within 600 Miles	923,408
All States Within 900 Miles	2,227,768

Table 17 provides a summary of the top 25 Food Manufacturing counties in the SERBEP region. Appendix L provides the top 25 broken out by industry type. The top 25 counties are represented by States that tend to have a high amount of fruit and vegetable processing industry, or flour based industry such as bakeries and confectionery.

Table 17: Top 25 Food Manufacturing County Estimates

State Name	County Name	Total Food Mfg. Tons/Year	Total Biomass Tons/Year
Tennessee	Hamilton	37,804	1,832,393
Florida	Polk	36,847	12,287,809
Florida	Manatee	33,557	5,429,802
North Carolina	Mecklenburg	33,028	1,799,407
Florida	Hillsborough	29,729	8,819,456
Florida	Dade	28,167	755,632
Georgia	Glynn	27,999	115,465
Missouri	St. Louis City	27,867	39,559
Florida	Palm Beach	26,004	717,138
Georgia	Fulton	23,390	789,656
Mississippi	Sunflower	20,429	122,107
Florida	Duval	20,394	1,868,875
Virginia	Newport News City	20,055	23,068
Tennessee	Shelby	20,030	1,887,117
Kentucky	Jefferson	19,364	774,080
Alabama	Hale	18,789	1,989,019
Mississippi	Humphreys	18,750	42,706
Alabama	Mobile	18,619	2,598,957
Alabama	Jefferson	16,437	1,081,328
Georgia	Muscogee	15,682	20,513
Florida	Orange	15,645	1,728,025
Missouri	St. Louis	14,658	266,901
Arkansas	Washington	14,469	12,144,874
Arkansas	Pope	14,447	3,498,005
South Carolina	Cherokee	14,102	787,797

Food Service

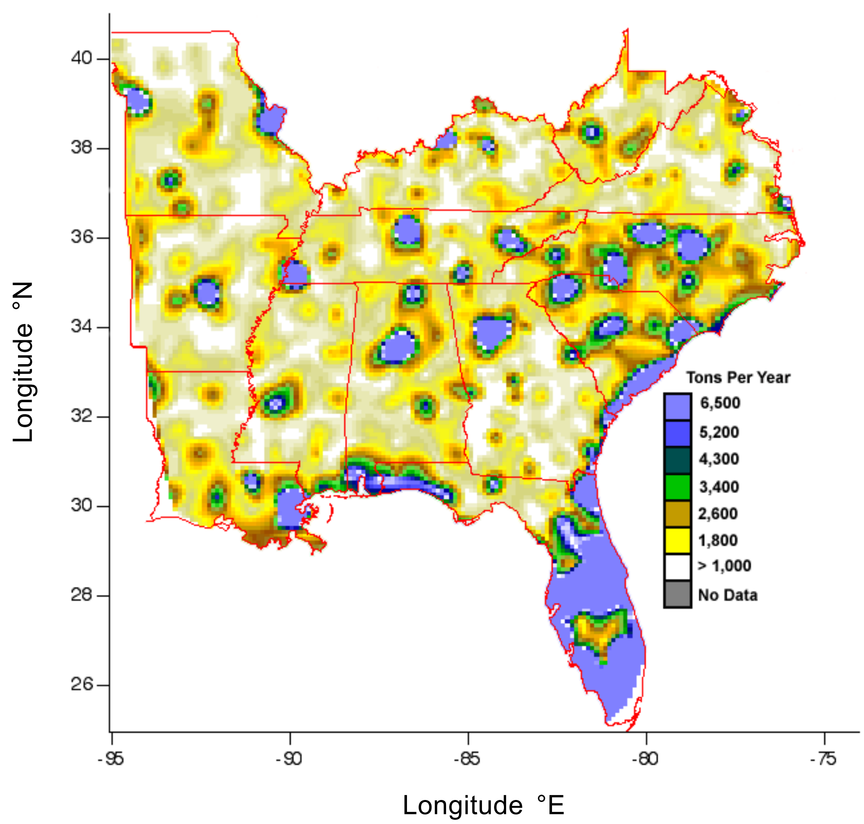
Another important source of food waste and other organic wastes include a range of Food Service businesses including restaurants, eating and drinking establishments and grocery stores. These services generate an estimated 5 to 10 pounds per employee per day, depending on the type. The Food Service industry, for the purposes of this analysis, is represented by entities where the general public goes to eat or receive some type of food related service, such as restaurants & eating/drinking places, hotels, and grocery stores. Table 18 provides the Food Service estimates by industry. Not included in this analysis are Food Service industries such as amusement parks, cruise ships, educational facilities, hospitals, nursing and personal care facilities, prisons and military installations. These obviously represent feedstock point sources that could add to the volume.

Table 18: Food Service Estimates by Industry

Region	Grocery Stores Tons/year	Restaurants, Drinking Places Tons/year	Hotels Tons/year
South Carolina	78,830	5,777	38,108
Adjoining SERBEP States	464,389	25,883	213,320
All SERBEP	1,331,212	89,224	621,906
SERBEP Within 300 miles	329,940	18,297	135,105
SERBEP Within 600 Miles	758,548	42,649	275,792
SERBEP Within 900 Miles	1,056,037	63,230	457,029
All States Within 300 miles	329,940	18,297	139,686
All States Within 600 Miles	870,082	57,092	375,021
All States Within 900 Miles	1,893,275	176,331	781,947

Figure 5 provides the Food Service density mapping. In evaluating the distribution of Food Service biomass wastes by region, it is interesting to note that generation of food waste in the food service sectors is very closely tied to population. In other words, the counties with the highest population have more restaurants and other facilities and thus generate equivalently higher quantities of food waste.

Figure 5: Food Sevice Waste



It is important to note, however, that this portion of the organic waste stream will likely be the most difficult to collect, consolidate and transport to a Biomass/Cogen facility outside of manure. This is due to the high number of smaller generators spread out over a wide area, as well as the mixed nature of the overall waste stream at these generators. Table 19 provides the Food Service estimates for selected regions around the Cowpens site.

Table 19: Food Service Estimates by Region

Region	Food Service Tons/year
South Carolina	122,714
Adjoining SERBEP States	703,591
All SERBEP	2,042,342
SERBEP States Within 300 Miles	483,343
SERBEP States Within 600 Miles	1,076,989
SERBEP States Within 900 Miles	1,576,296
All States Within 300 miles	487,924
All States Within 600 Miles	1,302,194
All States Within 900 Miles	2,851,552

Table 20 below provides the top 25 Food Service counties. This table is heavily represented by heavily populated urban areas, and particularly by Florida counties due to the large urban areas and concentration of Food Service entities connected to Florida's tourist and entertainment industries.

Table 20: Top 25 Food Service County Estimates

State Name	County Name	Grocery Stores Tons/Year	Eating & Drinking Places Tons/Year	Hotels Tons/Year	Food Retail Tons/Year	Total Biomass Tons/Year
Florida	Dade	39,527	2,598	36,353	78,479	755,632
Florida	Orange	16,816	1,739	58,716	77,271	1,728,025
Florida	Broward	34,966	2,850	17,483	55,298	2,286,066
Georgia	Fulton	16,305	2,950	22,837	42,092	789,656
Florida	Palm Beach	24,619	1,301	11,169	37,089	717,138
Florida	Pinellas	19,158	1,465	12,779	33,402	36,684
Missouri	St. Louis	19,150	1,130	12,319	32,599	266,901
Louisiana	Orleans	7,516	3,681	19,886	31,083	93,708
Tennessee	Shelby	19,994	1,191	8,888	30,073	1,887,117
Florida	Hillsborough	18,849	1,092	9,274	29,215	8,819,456
Tennessee	Davidson	10,412	880	16,864	28,156	1,622,584
North Carolina	Mecklenburg	14,876	1,920	8,940	25,736	1,799,407
Kentucky	Jefferson	17,691	1,748	5,888	25,327	774,080
Florida	Duval	18,046	1,004	5,116	24,166	1,868,875
Alabama	Jefferson	13,301	917	5,451	19,669	1,081,328
Florida	Lee	9,361	762	8,901	19,023	1,410,275
Georgia	Cobb	13,454	394	4,655	18,503	277,587
Missouri	Jackson	10,083	1,281	7,132	18,496	2,033,789
North Carolina	Wake	12,284	838	4,960	18,082	1,313,649
Florida	Volusia	10,090	1,559	5,634	17,282	1,407,028
Georgia	Gwinnett	13,027	251	2,874	16,152	544,216
South Carolina	Horry	4,249	1,721	9,960	15,931	1,156,404
Georgia	De Kalb	11,506	903	3,369	15,778	122,929
Virginia	Fairfax	15,417	345	0	15,761	169,258
Arkansas	Pulaski	9,131	928	4,367	14,426	1,326,740

Pulp and Paper

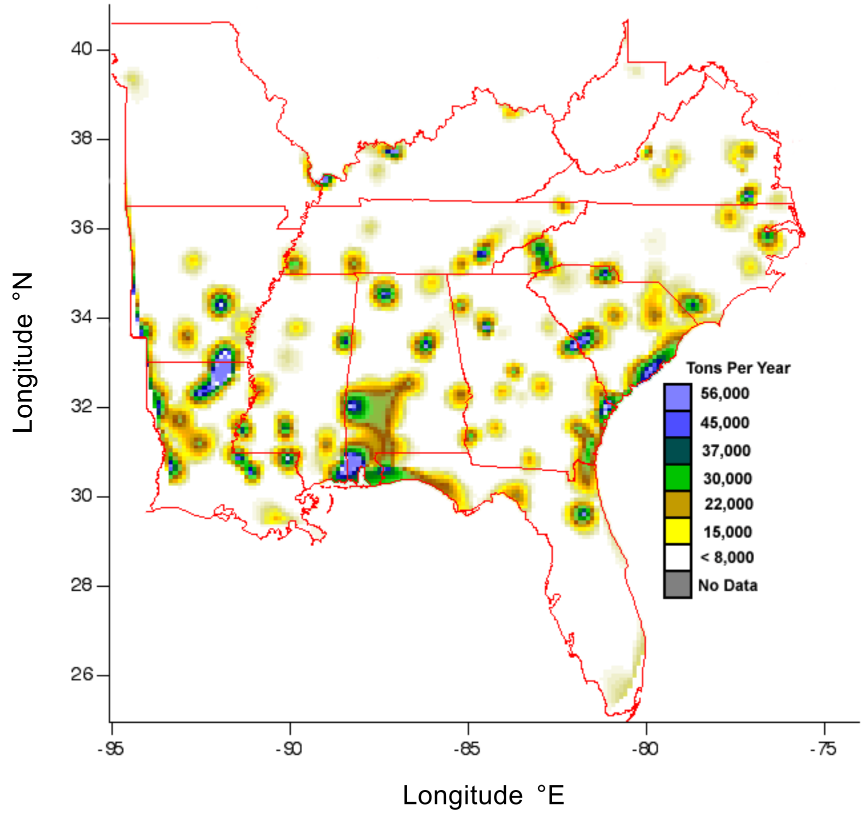
The Pulp and Paper sector represents an excellent biomass source of feedstock materials. These materials are the result of pulping, papermaking and paperboard manufacturing facilities, where waste cellulose fiber and wood residuals result from mill operations. This material is homogenous in nature and can provide cellulose to the Biomass/Cogen facility which is an excellent anaerobic digestion feedstock. Care must be taken to understand a particular mill's process, particularly as it relates to their own biological treatment methods. Indeed, mills typically treat their process water to prevent aerobic and anaerobic biological activity in mill pipelines and equipment. Some mill treatment could result in waste cellulose fiber that has biocide residuals, which can kill or reduce the Biomass/Cogen organisms required for anaerobic digestion. Table 21 provides for the Pulp and Paper biomass estimate by region.

Table 21: Pulp and Paper Estimates by Region

Region	Pulp and Paper Tons/year
South Carolina	250,221
Adjoining SERBEP States	1,166,139
All SERBEP	3,260,124
SERBEP States Within 300 Miles	616,339
SERBEP States Within 600 Miles	1,704,355
SERBEP States Within 900 Miles	2,489,052
All States Within 300 miles	795,331
All States Within 600 Miles	2,323,922
All States Within 900 Miles	3,852,393

Figure 6 provides the Pulp and Paper density mapping. The Pulp and Paper Industry is represented by a limited number or very large mills with very high volume operations compared to other industries. It is not unusual to have 50 to 200 tons per day of cellulose and/or wood residuals coming off a large paper mill. The material stream targeted is the primary clarified sludge from process water or wastewater treatment.

Figure 6: Pulp and Paper Waste



The material represents an excellent opportunity because it is a large volume located at one point source, ideal for recovery and procurement. Table 22 provides the top 25 Pulp and Paper counties, which correspond to areas where a large mill exists.

Table 22: Top 25 Pulp and Paper County Estimates

State Name	County Name	Total Paper Tons/year	Total Biomass Tons/year
Louisiana	Morehouse	121,295	478,442
Alabama	Mobile	114,056	2,598,957
Georgia	Fulton	72,056	789,656
Georgia	Chatham	72,056	243,056
Kentucky	Daviess	68,131	3,098,397
Kentucky	Ballard	68,131	302,078
Virginia	Southampton	61,579	567,135
Virginia	Covington City	61,579	61,882
Georgia	Richmond	59,662	488,145
Tennessee	Mcminn	58,451	4,983,566
Arkansas	Little River	55,638	1,306,270
Arkansas	Jefferson	55,638	375,041
Arkansas	Ashley	55,638	353,743
Alabama	Lawrence	53,226	1,403,345
Alabama	Talladega	53,226	1,268,648
Alabama	Choctaw	53,226	320,976
Louisiana	Washington	51,984	3,897,985
Louisiana	East Baton Rouge	51,984	3,161,076
Louisiana	Beauregard	51,984	1,657,722
Louisiana	De Soto	51,984	1,439,585
Louisiana	Ouachita	51,984	1,147,980
Louisiana	West Feliciana	51,984	488,226
Louisiana	Jackson	51,984	185,957
South Carolina	York	51,607	1,880,085
South Carolina	Aiken	51,607	764,672

Total Generated Biomass

The total biomass generated in the South Carolina and SERBEP region is represented by the Animal Manure, Animal Residuals, Food Manufacturing, Food Service and Pulp and Paper sectors detailed in the above sections. This represents a very significant amount of biomass feedstock materials, with an order of magnitude in the billions for animal manure and in the millions of tons for the other targeted biomass. The estimated generated amount is more than enough to feed the Biomass/Cogen facility, which will require between 150,000 to 175,000 tons per year. Table 23 provides a summary of the total animal manure and related biomass estimates by sector for different regions that would represent some of the desired Biomass/Cogen raw material procurement program's SERBEP and Non SERBEP geographic areas.

Table 23: Total Generated Biomass Summary Estimates by Sector

Region	Animal Manure Tons/year	Food Manufacture Tons/year	Animal Residuals Tons/Year	Pulp and Paper Tons/year	Food Service Tons/year
South Carolina	31,694,689	45,965	242	250,221	122,714
Adjoining SERBEP States	378,740,812	514,927	5,547	1,166,139	703,591
All SERBEP	1,235,140,748	1,507,104	10,581	3,260,124	2,042,342
SERBEP States Within 300 Miles	206,853,408	273,724	3,758	616,339	483,343
SERBEP States Within 600 Miles	641,319,989	792,184	6,740	1,704,355	1,076,989
SERBEP States Within 900 Miles	850,849,753	1,195,117	7,644	2,489,052	1,576,296
All States Within 300 miles	222,015,325	273,724	na	795,331	487,924
All States Within 600 Miles	724,605,535	923,408	na	2,323,922	1,302,194
All States Within 900 Miles	1,342,968,534	2,227,768	na	3,852,393	2,851,552

The estimates in Table 23 show that for every feedstock sector or type, except Animal Residuals, there is enough material generated in the SERBEP region to individually provide for the Biomass/Cogen facility raw material supply needs.

Table 24 provides the Total Biomass by region, with the generation estimates from the sector estimates, as well as a subtotal for non-manure Biomass. As is shown, the Animal Manure category dominates the rest of the categories for total tonnage, and it the largest biomass volume by far. For instance, the Animal Manure estimates for SERBEP generated material represent over 99% of the available generated total biomass (also the case for estimates using all states within 900 miles), while the Non-Manure category represents less than 1% (again, this is the case in all states within 900 miles). However, the tonnages in each case provide for generation rates which are more than enough to supply the Biomass/Cogen facility with a reasonable procurement program.

Table 24: Total Generated Biomass Estimates by Region

Region	Total Non-Manure Tons/year	Total Biomass Tons/year
South Carolina	186,085	32,113,833
Adjoining SERBEP States	1,911,664	381,131,016
All SERBEP	5,865,567	1,241,960,899
SERBEP States Within 300 Miles	1,079,211	208,230,572
SERBEP States Within 600 Miles	2,959,861	644,900,256
SERBEP States Within 900 Miles	4,402,451	856,117,862
All States Within 300 miles	1,556,980	223,572,305
All States Within 600 Miles	4,549,524	729,155,059
All States Within 900 Miles	8,931,713	1,351,900,247

Another way to determine generated material is to look at the material that is generated within a certain tipping fee range found in a regional area. This will provide an indication of how much biomass feedstock is potentially available within a certain geographical area that has a tipping fee cost associated with its disposal. This allows the evaluation of how much biomass is generated within a certain tipping fee area, and so how to target the procurement program to maximize revenue. Table 25 below provides tipping fee based biomass generation estimates for each sector as well as the total biomass, and a subtotal for non-manure biomass generation estimates.

Table 25: Tipping Fee Based Biomass Estimates

Tipping Fee	$50/ton	$40/ton	$30/ton	$20/ton	$10/ton	$0/ton
Animal Manure	7,459,188	49,891,247	132,013,435	277,068,977	479,156,859	620,874,989
Animal Residuals	116	908	2,148	4,127	7,292	8,579
Food Manufacturing	11,937	76,617	168,914	328,757	480,636	709,864
Food Service	27,134.8	120,548	285,604	582,269	821,931	1,204,977
Pulp and Paper	21,135	159,290	714,781	2,030,917	3,152,388	5,752,681
Non-Manure Biomass	60,323	357,363	1,171,447	2,946,070	4,462,247	7,676,101
Total Biomass	7,519,511	50,248,610	133,184,882	280,015,047	483,619,106	628,551,090

The above estimates show that at a $30 per ton tipping fee, except for the Animal Residuals sector, there is enough biomass feedstock material generated in each sector alone to individually supply the Biomass/Cogen facility's raw material needs. Table 26 provides the top 25 total biomass counties with the supporting sector by sector generation estimates. As expected, Animal Manure generation estimates dominate the top 25 county results. This table is heavily represented by areas with large animal production centers, typically areas that use CAFO production methods. North Carolina counties are particularly represented due to the large concentration of hog CAFO production areas. Florida is well represented due to a concentration of cattle production.

Table 26: Top 25 Total Biomass County Estimates

State Name	Name	Animal Manure Tons/year	Food Manufacture Tons/year	Animal Residuals Tons/year	Pulp and Paper Waste Tons/year	Food Retail Tons/year	Total Biomass Tons/Year
N. Carolina	Duplin	30,689,291	3,576	191	0	841	30,693,899
N. Carolina	Sampson	14,342,566	530	241	0	869	14,344,205
Florida	Polk	12,238,541	36,847	10	276	12,135	12,287,809
Arkansas	Washington	12,127,125	14,469	72	0	3,208	12,144,874
Arkansas	Benton	11,504,891	4,438	76	0	1,932	11,511,336
Virginia	Rockingham	9,671,916	2,368	163	0	714	9,675,161
Missouri	Greene	8,916,211	7,239	231	0	6,154	8,929,835
Florida	Hillsborough	8,760,219	29,729	16	276	29,215	8,819,456
Virginia	Augusta	7,630,508	3,959	0	0	650	7,635,117
N. Carolina	Wayne	7,551,704	7,389	241	0	1,826	7,561,161
Missouri	Lawrence	7,116,442	569	6	0	320	7,117,337
Florida	Hendry	6,936,825	3,594	0	0	338	6,940,758
Florida	Osceola	6,798,089	1,523	0	0	12,110	6,811,722
Louisiana	Tangipahoa	6,342,240	6,958	11	0	1,917	6,351,126
Tennessee	Greene	6,183,684	184	0	0	1,409	6,185,277
Florida	Okeechobee	6,144,045	294	0	0	949	6,145,289
N. Carolina	Iredell	5,871,938	1,821	13	0	3,216	5,876,987
Missouri	Barry	5,871,901	573	244	0	542	5,873,260
Missouri	Franklin	5,857,484	762	15	0	1,166	5,859,427
Florida	Highlands	5,797,204	1,399	0	0	3,144	5,801,747
Missouri	Jasper	5,683,233	4,858	231	0	1,886	5,690,207
Alabama	Montgomery	5,632,061	8,257	5	0	5,611	5,645,934
Missouri	Howell	5,557,782	175	1	0	920	5,558,878
Florida	Manatee	5,390,904	33,557	0	0	5,341	5,429,802
N. Carolina	Robeson	5,387,121	10,065	24	4,317	2,534	5,404,061

To eliminate the overwhelming effect of Animal Manure and determine the best opportunity for non-manure procurement by county, Table 27 provides the top 25 non-manure county generation estimates. The accompanying total biomass estimates, which are heavily influenced by manure, are also provided.

Table 27: Top 25 Total non-manure Biomass County Estimates

State Name	County Name	Animal Residuals (Tons/Year)	Food Manufacture (Tons/year)	Food Retail (Tons/Year)	Pulp and Paper (Tons/Year)	Total Non-manure (Tons/year)	Total Biomass Tons/Year
Alabama	Mobile	18,619	1	114,056	8,838	141,514	2,598,957
Georgia	Fulton	23,390	57	72,056	42,092	137,595	789,656
Louisiana	Morehouse	48	0	121,295	348	121,691	478,442
Florida	Dade	28,167	18	4,835	78,479	111,498	755,632
Florida	Orange	15,645	0	0	77,271	92,916	1,728,025
Georgia	Chatham	7,930	3	72,056	8,475	88,464	243,056
Tennessee	Shelby	20,030	6	33,434	30,073	83,543	1,887,117
Kentucky	Daviess	6,389	49	68,131	2,942	77,511	3,098,397
Georgia	Richmond	7,869	14	59,662	6,373	73,918	488,145
Louisiana	E. Baton Rouge	6,450	2	51,984	10,798	69,234	3,161,076
Tennessee	Hamilton	37,804	62	21,042	9,650	68,558	1,832,393
Kentucky	Ballard	0	0	68,131	128	68,259	302,078
S. Carolina	Charleston	1,225	0	51,607	14,285	67,117	414,950
Florida	Broward	10,703	5	276	55,298	66,282	2,286,066
Georgia	Glynn	27,999	0	30,881	7,036	65,916	115,465
Florida	Duval	20,394	20	20,721	24,166	65,301	1,868,875
Florida	Palm Beach	26,004	2	0	37,089	63,095	717,138
Virginia	Covington City	0	0	61,579	304	61,882	61,882
Virginia	Southampton	29	0	61,579	130	61,738	567,135
Tennessee	Mcminn	1,392	0	58,451	731	60,574	4,983,566
N. Carolina	Mecklenburg	33,028	1	1,480	25,736	60,246	1,799,407
Florida	Hillsborough	29,729	16	276	29,215	59,237	8,819,456
Arkansas	Jefferson	698	38	55,638	1,555	57,929	375,041
Louisiana	Ouachita	3,268	0	51,984	2,656	57,907	1,147,980
S. Carolina	York	609	0	51,607	4,474	56,691	1,880,085

Available Feedstock Survey Results

The generated biomass estimates above are useful for providing an indication of what is generated in a certain geographical area or under a certain tipping fee based disposal cost. However, it is important to apply reasonable recovery rates for procurement so that a realistic look at the "available" target biomass feedstocks is obtained. Available material is the percent of material that can reasonably be expected to be available for recovery efforts based on competitive forces and existing infrastructure. Based on industry data along with RRSI's expert solid waste policy, material recovery experience and in-house database, a percent recovery factor was applied to each of the targeted feedstock sectors to determine availability. The sector by sector percent recovery rates applied for estimates are as follows:

- Animal Manure = 1% recovery rate of the estimated generated materials
- Animal Residuals = 25% recovery rate of the estimated generated materials
- Food Manufacturing = 20% recovery rate of the estimated generated materials
- Food Service = 10% recovery rate of the estimated generated materials
- Pulp and Paper = 25% recovery rate of the estimated generated materials

The above recovery rates are based on current practices and infrastructure, as well as the basis and conversion factors that were used to estimate the original generated feedstock numbers.

Total Available Biomass

Animal Manure's recovery rate is only 1% because the current practices are not yet in line with direct costs being applied for disposal, and because certain infrastructure needs to be put in place. This low recovery rate may increase dramatically if CAFO and lagoon practices are scrutinized and regulated more closely. Animal Residuals, Food Manufacturing and Pulp and Paper recovery rates are between 20% -25% because the mill residual biomass materials are at concentrated, easy to access industrial sites. This promotes a higher recovery rate and availability. Food Service's recovery rate is 10% because the entities are smaller and spread out, requiring a more sophisticated procurement program to collect and transport the biomass materials to the Biomass/Cogen facility site. Table 28 below provides the available biomass estimates using these recovery rates against the previously provided biomass generation estimates.

Table 28: Total Available Biomass Estimates by Sector

	Animal Manure Tons/year	Food Manufacture Tons/year	Animal Residuals Tons/Year	Pulp and Paper Tons/year	Food Service Tons/year
Recovery Rate in Percent	1%	20%	25%	25%	10%
South Carolina	316,947	9,193	61	62,555	12,271
Adjoining SERBEP States	3,787,408	102,985	1,387	291,535	70,359
All SERBEP	12,351,407	301,421	2,645	815,031	204,234
SERBEP States Within 300 Miles	2,068,534	54,745	939	154,085	48,334
SERBEP States Within 600 Miles	6,413,200	158,437	1,685	426,089	107,699
SERBEP States Within 900 Miles	8,508,498	239,023	1,911	622,263	157,630
All States Within 300 miles	2,220,153	54,745	na	198,833	48,792
All States Within 600 Miles	7,246,055	184,682	na	580,981	130,219
All States Within 900 Miles	13,429,685	445,554	na	963,098	285,155

Table 29 provides the summary estimates for available total biomass and non-manure biomass for different regions using the above recovery rate applications. The data shows that there is enough biomass in the State of South Carolina alone to provide ample feedstock to the Biomass/Cogen facility. If concerns about Animal Manure procurement are evident, then the non-manure subtotal shows that there is more than enough of the available non-manure biomass feedstock material if South Carolina and the adjoining SERBEP States are used for raw material procurement.

Table 29: Total Available Biomass Estimates by Region

	Total Non-Manure Tons/year	Total Biomass Tons/year
South Carolina	84,080	789,783
Adjoining SERBEP States	466,266	4,253,674
All SERBEP	1,323,331	13,674,739
SERBEP States Within 300 Miles	258,103	2,326,637
SERBEP States Within 600 Miles	693,909	7,107,109
SERBEP States Within 900 Miles	1,020,827	9,529,324
All States Within 300 miles	302,370	2,522,523
All States Within 600 Miles	895,881	8,141,937
All States Within 900 Miles	1,693,807	15,123,492

Tables 28 and 29 show that there is so much Animal Manure produced that it represents approximately 90% of the available biomass estimates, even considering its low recovery rate of 1%. A very conservative way of looking at the available material is to use the recovery rates in combination with the tipping fee based generation estimates. Table 30 provides estimates using this method for determining the available tipping fee based biomass feedstock materials (See Figure 6 in the next section).

Table 30: Total Available Biomass Estimates by Tipping Fee

Tipping Fee	Recovery Rate	$50/ton	$40/ton	$30/ton	$20/ton	$10/ton	$0/ton
Animal Manure	1%	74,592	498,912	1,320,134	2,770,690	4,791,569	6,208,750
Animal Residuals	25%	29	227	537	1,032	1,823	2,145
Food Manufacturing	20%	2,387	15,323	33,783	65,751	96,127	141,973
Food Service	10%	2,713	12,055	28,560	58,227	82,193	120,498
Pulp and Paper	25%	5,284	39,823	178,695	507,729	788,097	1,438,170
Non-Manure Biomass	---	10,414	67,428	241,575	632,739	968,240	1,702,786
Total Biomass	---	85,006	566,340	1,561,710	3,403,429	5,759,809	7,911,535

Using this method, an average tipping fee target of $40 per ton will supply enough available total biomass feedstock from the regional areas to supply the Biomass/Cogen facility's needs, while an average tipping fee target of $30 per ton will supply enough feedstock if only non-manure biomass is targeted.

Future Feedstock Considerations

The feedstock generation survey results from above show that there is more than enough animal manure and related biomass material currently available to supply the Biomass/Cogen facility. The estimates above were based on conservative multipliers and conversion factors for the feedstock generation rate estimates, as well as conservative percent recovery rates for the feedstock availability estimates. Many of the feedstock's current practices used for disposition will be eliminated or changed towards more expensive cost factors in the future, due to regulation or industry forces. The future manure and biomass feedstock availability in all feedstock sectors could increase significantly with application of these new factors.

Animal Manure is a biomass feedstock source that could become significantly more available. The feedstock generation data shows that billions of tons are estimated as produced in the SERBEP region. Most of this material is now treated as a "zero" cost, in that disposal methods are unregulated enough to allow for minimal or no treatment. Even using a very low 1% recovery rate, to reflect the situation where the material that potentially would be currently available from regional CAFO operations that now have disposal problems, the available manure is a large number. The percent recovery rate could go up significantly in the future because concerns about watersheds, land resources and manure to methane to global warming effects will increase pressure to adopt more environmentally sound disposal methods. The added cost of these new practices could make a Biomass/Cogen facility an attractive lower cost option for some manure materials.

For example, according to representatives in the poultry industry, the current poultry manure disposal practices are under new regulatory pressure, which could change drastically the disposal methods. This could take effect as early as this late this year. The proposed new regulations would govern the land application of manure as a fertilizer substitute and could limit the amount of poultry manure that is spread in key regional areas necessarily in close proximity to the animal production facilities. Historically fertilizer has been applied based on the nitrogen content and level's effect, so that application of the poultry manure could be made up to the desired nitrogen level without concern for the phosphate or potassium overloading. However, in recent years the phosphate content has been under intense scrutiny due to it's detrimental effects on rivers, lakes and watersheds.

Problematic poultry manure is generated in confined animal production facilities and comes off as a solid material, typically consisting of 50% pine shavings and 50% poultry manure. This material has a 2-2-2 nitrogen/phosphate/potassium ratio, whereas most fertilizers it replaces have a target 16-4-4 nitrogen/phosphate/potassium ratio. Proposed new land application regulations designed to control fertilization methods based on the phosphate loading are a year overdue and expected to be released and adopted soon. This would effectively reduce the poultry manure application by up to 75%. This manure would then become a disposal problem for poultry producers, and would be more available to meet the feedstock needs of the Biomass/Cogen facility. These regulations would effect liquid manure fertilizer land applications as well.

Another example of new regulatory pressures on Animal Manure that could significantly increase its future availability as biomass feedstock, is the work towards improved Animal Manure disposal practices at CAFO sites. This work's focus is the phasing out of anaerobic treatment lagoons associated with CAFO sites, particularly in North Carolina's hog industry. Past industry lagoon treatment practices have come upon severe criticism for pollution of waterways and groundwater, and air emission and/or odor concerns in what is becoming more highly populated rural areas. Recently the State of North Carolina and Smithfield Foods, the largest producer of hogs, agreed to a phasing out of aerobic treatment lagoons in the State's hog industry. Smithfield also announced it is providing for $15 million in research funding for a leading university to develop new ways of disposing of hog manure. The development of new technologies or material handling systems could allow cost effective transportation of animal manures, extending the range of the Biomass/Cogen facility to procure even liquid manure sources.

The other biomass feedstocks also have new regulatory and industry pressures that could greatly increase their availability. For the Animal Residuals and Food Manufacturing sector, new land application regulations or guidelines for disposing of these materials may increase the available amounts. For the Animal Residuals sector, industry pressures for pathogen control in food and animal feed areas like "mad cow disease" will require much more stringent quality control of the animal slaughterhouse residuals. The Animal Residuals conversion factors used to develop the generation rates were very low, reflecting only the wastewater treatment clarification residuals. The concern over various animal slaughterhouse waste components for re-use could increase the generation estimates by an order of magnitude, thereby greatly increasing this feedstock's availability.

Waste Management Infrastructure

An overview of the regulatory and key permitting regulations and guidelines specific to the Cowpens site was previously provided. Since the State of South Carolina generally follows federal regulations, policy and guidelines, there are some important federal waste management policies and guidelines, as well as new industry pressures, that can also serve as the basis of a biomass waste management strategic planning. This strategy can be used to determine the impact on the facility and the appropriate procurement program.

Regulatory Impacts on Waste Management Practices

Regulatory areas of concern can impact the plant operations directly via facility regulation or indirectly as a result of "other industry" regulation that can affect facility support requirements such as animal manure and biomass feedstock sourcing, composted product distribution, etc. The following section addresses some of these areas of concern as it relates to the general impacts on waste management requirements for future raw material procurement and facility operations. This section also describes the waste management policy environment in which the Biomass/Cogen facility would be implemented. Included is discussion of federal regulations for waste disposal and transportation, and the approach to managing solid waste and waste recovery.

RCRA Subtitle D: Non Hazardous Waste:

The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. 6942(b)) (RCRA), is the primary federal statute governing solid waste management. The principal objectives of RCRA are far-reaching and complementary:

1. Promote the protection of human health and the environment from potential adverse effects of improper solid waste management;
2. Conserve material and energy resources through source reduction and recycling;
3. Assist in the development of solid waste management plans;
4. Improve solid waste management practices; and
5. Promote the demonstration, construction, and application of solid waste management, resource recovery, and resource conservation systems which preserve and enhance the quality of air, water, and land resources.

Federal Guidelines for Solid Waste Management Plans:

The United States Environmental Protection Agency guidelines assist in the development and implementation of State solid waste management plans in accordance with RCRA. These guidelines contain methods for achieving the objectives of environmentally sound management and disposal of solid and hazardous waste, resource conservation, and maximum utilization of valuable resources. These guidelines address the minimum requirements for approval of State plans. The plans must prohibit the establishment of new open dumps within the State, and contain requirements that all solid waste (including solid waste originating in other States, but not including hazardous waste) shall be (i) utilized for resource recovery or (ii) disposed of in sanitary landfills or otherwise disposed of in an environmentally sound manner. The plan must also provide for the closing or upgrading of all existing open dumps.

No local government within the State may be prohibited under State or local law from entering into long-term contracts for the supply of solid waste to resource recovery facilities. The state plan must also provide for resource conservation or recovery and for the disposal of solid waste in sanitary landfills or for any combination of practices that may be necessary to use or dispose of such waste in a manner that is environmentally sound. In addition, a policy and strategy for encouragement of resource recovery and conservation activities must be developed. To encourage resource recovery and conservation, the State should provide for technical assistance, training, information development and dissemination, financial support programs, market studies and market development programs.

Municipal Solid Waste (MSW) Definitions:

The Biomass/Cogen facility targets animal manure and related biomass feedstocks such as Animal Slaughter/Processing residuals Food Manufacturing residuals, Food Service residuals and Pulp and Paper mill residuals. These biomass feedstocks, with the exception of Food Service residuals, are agricultural and industrial sources and are not typically labeled as MSW wastes. However, Food Service residuals and some of the other feedstock sources may apply to MSW standards or indeed come in under the MSW based waste hauling infrastructure and control. The EPA defines MSW to include "wastes such as durable goods, nondurable goods, containers and packaging, food scraps, yard trimmings, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources. Examples of waste from these categories also include appliances, newspapers, clothing, boxes, disposable tableware, office and classroom paper, wood pallets, and cafeteria wastes. The Biomass/Cogen facility could readily take food wastes, cafeteria wastes, and yard trimmings if a homogenous stream or a suitable volume could be developed, thereby falling under the MSW guidelines. MSW does not include wastes from other sources, such as construction and demolition (C&D) waste, municipal sludges, combustion ash, and industrial process wastes that might also be disposed of in municipal waste landfills or incinerators. EPA's estimate of waste generation is an estimate of the generation of MSW only.

Impacts of Methane from Landfills:

The Biomass/Cogen facility can be strategically looked at as a "no landfill waste hauling infrastructure facility." The facility concept is unique in that it can act as an alternative to landfilling without being competitive or detrimental to the current waste industry hauling practices, and can work in compliment with the existing infrastructure and industry market forces. Alternatives to landfill disposal is a key area of national concern due to a typical landfill's potential negative impacts on the environment. One area of great concern is the production of landfill gas. Landfill gas, which is comprised mainly of methane and carbon dioxide, results from the anaerobic (in the absence of oxygen) decomposition of organic degradable wastes buried in the landfill. The gas production process begins when waste is put into the landfill and can continue for 30 years or more. Wastes currently buried in municipal landfills are biologically decaying and releasing large quantities of methane to the atmosphere. These gases become "greenhouse active" and impact global warming and other air quality issues. Efforts to harness the gas at the landfill can be very costly per the amount of landfill biogas captured. Additionally, landfill gas can contain high amounts of sulfur or other contaminants that present air emission problems when used.

The EPA estimates that emissions from manure management account for about 10% of the total methane emissions in 1995. Methane's increasing concentration in the atmosphere has important implications for global climate change and other air standards. Methane is very effective at absorbing infrared radiation (IR) given off by the Earth's surface. By absorbing IR and inhibiting its release into space, the presence of methane contributes to increased atmospheric and surface temperatures. This process is commonly referred to as "the greenhouse effect." In addition to this direct radiative impact (also called radiative forcing), methane's participation in chemical reactions in the atmosphere indirectly contributes to global warming by influencing the amount of ozone in the troposphere, hydroxyl in the troposphere, and water vapor in the stratosphere. Methane's indirect impacts are expected to be about equal in magnitude to its direct impacts. Overall, one gram of methane has the impact of about 21 grams of carbon dioxide over a 100 year period. This value of 21 is the 100-year global warming potential (GWP). Over a 50-year time frame, one gram of methane would have the impact of about 60 grams of carbon dioxide, i.e., a 50 year GWP of 60. Methane's high GWP and relatively short lifetime make it possible to mitigate global warming quickly by reducing methane emissions.

The United States Environmental Protection Agency promulgated emission guidelines for municipal solid waste landfills in 1996. State plans must include controls of MSW landfill emissions at each MSW landfill meeting the following three conditions:

(1) The landfill has accepted waste at any time since November 8, 1987, or has additional design capacity available for future waste deposition;

(2) The landfill has a design capacity greater than or equal to 2.5 million megagrams or 2.5 million cubic meters. The landfill may calculate design capacity in either megagrams or cubic meters for comparison with the exemption values. Any density conversions shall be documented and submitted with the report; and
(3) The landfill has a nonmethane organic compound (NMOC) emission rate of 50 megagrams per year or more.

The State plan shall include the installation of a collection and control system at each MSW landfill meeting the previous conditions. States must develop provisions for the control of collected MSW landfill emissions through the use of control devices. The control devices can include the following:

(1) An open flare designed and operated in accordance with established operating parameters; or
(2) A control system designed and operated to reduce NMOC by 98 weight percent; or
(3) An enclosed combustor designed and operated to reduce the outlet NMOC concentration to 20 parts per million as hexane by volume, dry basis at three percent oxygen, or less.

Future emphasis on landfill alternatives to better harness biomass waste produced biogas is a key priority. Redirecting the biomass waste from landfills to a Biomass/Cogen type facility can provide for superior biogas production and a more beneficial use of the biomass resources. A Biomass/Cogen facility is an option that can potentially provide a more sustainable and cost effective solution for the above guidelines.

Rule 503—Standards for the Use or Disposal of Sewage Sludge

The EPA established a rule, which consists of general requirements, pollutant limits, management practices, and operational standards, for the final use or disposal of sewage sludge generated during the treatment of domestic sewage in a treatment works. Standards apply to sewage sludge applied to the land, placed on a surface disposal site, or fired in a sewage sludge incinerator. The rules also include pathogen and alternative vector attraction reduction requirements for sewage sludge applied to the land or placed on a surface disposal site. The rules apply to any person who prepares sewage sludge, applies sewage sludge to the land, or fires sewage sludge in a sewage sludge incinerator and to the owner/operator of a surface disposal site. If the facility compost products (or indeed certain feedstock raw materials) is considered as an "industrial sludge," the dewatered residual from an industrial process, the South Carolina water pollution regulations for disposition of industrial sludge indicate that the material would be dealt with under regulations for solid waste:

> 61-9.504.4 Relationship to other regulations:
>
> (b) The disposal of industrial sludge involving the composting or co-composting of the industrial sludge with yard trash, land-clearing debris, or a combination of yard trash and land clearing debris shall comply with the requirements established by the Department in R.61-107.4 [Solid Waste Management: Yard Trash and Land-Clearing Debris; and Composting]. The submission and information requirements shall be determined by the Department.
>
> (c) The disposal of industrial sludge utilizing an innovative and experimental solid waste management technology or process shall be permitted under R.61-107.10. [Solid Waste Management: Research, Development and Demonstration Permitting].

The rule does not establish requirements for processes used to treat domestic sewage or for processes used to treat sewage sludge prior to final use or disposal. The determination of the manner in which sewage sludge is used or disposed is a local determination. The rule also does not establish requirements for sewage sludge co-fired in an incinerator with other wastes or for the incinerator in which sewage sludge and other wastes are co-fired. Other wastes do not include auxiliary fuel fired in a sewage sludge incinerator.

Flow Control and Interstate Commerce:

Flow control and interstate transportation of waste are the two major issues currently being contested across the country. Interstate transportation of waste means, for example, shipping waste from states like New York and New Jersey that have limited landfill capacity and high tipping fees, to states like Pennsylvania, Ohio, and Indiana that have large capacity and lower fees. Several states have enacted laws restricting the importation of waste from other states, but theses laws have been struck down by the United States Supreme Court on the grounds that these laws, without explicit authorization from Congress, interfere with commerce under the Interstate Commerce Clause of the United States Constitution.

Flow controls can be legally used by State and local governments to designate where MSW and industrial solid waste must be taken for processing, treatment or disposal. This waste management approach requires waste to be delivered to specific facilities such as waste-to-energy (WTE) facilities, materials recovery facilities (MRFs), composting facilities, transfer stations and/or landfills. The facilities can be either publicly or privately owned. One of the direct effects of flow control is that designated facilities are assured of receiving a guaranteed amount of MSW, industrial solid waste and/or recyclable materials. If the designated facilities charge a "tipping fee" for receipt of the MSW/recyclables, flow control assures a source of revenue to meet their capital and operating costs.

Flow controls have become a heavily debated issue among State and local governments, the waste management industry, recyclers, and environmental groups. Financial institutions have also been a part of the discussion because of the relationship between flow controls and financing of waste management facilities. These interested parties hold differing views on the environmental, planning, and economic benefits of flow controls. During the 1990s, several court decisions ruled against the use of flow controls. Notably, in May 1994, the United States Supreme Court in *C & A Carbone, Inc. v. Town of Clarkstown* decided that the use of flow control can discriminate against interstate commerce and, therefore, can violate the commerce clause of the United States Constitution. Legislation was introduced during the 103rd Congress to clarify the legal status of flow controls. A consensus bill was passed by the House of Representatives late in the session; the Senate did not act and the legislation died with this Congress. Similar legislation was introduced in the 104th Congress.

Interstate flow control of waste is unlikely to be an issue. Flow control to designated facilities within a county or region is of more interest to this project, but still will only be an issue where other facilities may be competing for the same feedstocks, or other facility designations already exist (such as waste-to-energy incinerators).

CAFO Standards and Changing Disposal Methods:

Concentrated Area Feedlot Operations (CAFO's) have come under greater scrutiny nationally as well as specifically in South Carolina, adjoining SERBEP States such as North Carolina, and the entire SERBEP region during the last few years. Animal manure produced in the United States was about 1.37 billion solid tons of waste. Recent studies indicate there is too much manure and too little land for continuation of the current CAFO manure disposition methodology. CAFO's by their nature produce a considerable amount of animal waste disposed of in a very concentrated area. Historically this animal waste has been managed through land application (direct injection) based on fertilizer substitution or intermediate lagoon treatment. Two new areas of regulation are being developed and will be implemented in the near future. These are critical for the CAFO industry, which will receive these two key regulations as applicable for their animal manure disposal practices:

- new regulations for phasing out animal manure waste lagoons and lagoon treatment methods, which will require new disposal and treatment methodologies that will convert animal wastes from "zero" charge disposal to a tipping fee or processing cost.

- new regulations limiting the application of animal manures as agricultural spreads, fertilizers, etc., based on phosphate standards instead of current nitrogen standards, resulting in up to a 75% reduction in the land loading capability and an increase in the pressure on solid and liquid manure disposal and "markets."

Geographic areas of particular concern to South Carolina include the North Carolina swine industry and the Piedmont regions as it relates to poultry, where in many instances it is likely that lagoon treatment will be discontinued and alternatives to lagoon treatment will be required. For instance, in North Carolina Smithfield Foods, the leading swine producer, and the State of North Carolina's Attorney General signed an agreement aimed to eliminate swine waste lagoons. This has been an overwhelming problem for North Carolina, effecting land and water resources that have impacted drinking water, recreational use and fisheries. Smithfield has committed $15 million to research alternative methods for swine manure disposal. In the Piedmont area the land application regulations of poultry manure may be reduced by as much as 75 percent due to new federal regulations requiring a switch from nitrogen to phosphate as the limiting guideline.

Recent legislation has also required that National Pollution Discharge Elimination System (NPDES) permits be completed for each of these CAFO's. Also, no more land application of any additional manure products will be allowed, and in some instances reductions in allowed applications are planned. In the affected regional area, State CAFO permits in addition to the NPDES paperwork are required. These permits along with ongoing operational data collection is designed to ensure that soil loadings of both phosphorous and nitrates to not exceed safe limits. The efforts to permit livestock programs are not limited to CAFO's. The same type of regulation is being implemented for range cattle operations as well as "non CAFO" poultry and swine farms.

New industry pressures also come from well organized groups and law firms that include Tobacco industry type lawsuits and tactics meant to force a quick change. These groups opposed CAFO's and CAFO disposal practices and are determined to change current practices faster than new government regulation can. Many of these groups strongly believe the current practices have been correctly deemed as detrimental. They believe that effects on land and water resources are well documented and are concerned about significant negative effects for land and water. There are also potential air quality concerns via unharvested methane effects as described in the above section. One group lead by Robert Kennedy Jr. "announced that they have recruited an all-star team of private bar attorneys and law firms to launch a broad legal assault against the corporate hog industry. Citing the government’s failure to prosecute industry practices that shatter rural communities, and contaminate public waterways, this public interest group said they will work with prominent plaintiffs lawyers to reform the industry, restore damaged ecosystems and reinvigorate America’s family farms. The new coalition has already initiated the first series of lawsuits in North Carolina and is hosting a national meeting of hog activists to support the effort."

On a state-by-state basis regulators and industry groups have been looking more closely at the loading rates that land application has been creating and finding that these loading rates are threatening both surface and ground water resources. Past disposition practices and methodology as fertilizers and agricultural spread have resulted in serious solid waste/landfill overloading, and the concentrated materials becoming pollutants overloading rivers, streams, lakes, groundwater. Overall it appears that the future trend in manure management is moving from one hundred percent land application to the need for significant offsite processing and treatment, particularly in regions where concentrated CAFO industry has developed and overburdened the region's. This trend should allow a future Biomass/Cogen facility to begin to accept material on a tip fee basis where it was once land applied for "zero" cost.

Waste Hauling Infrastructure Considerations:

The ability to recover organic wastes varies by the type of waste generated. For instance, with animal manures it must be assumed that the transportation of manures, particularly wet manures, would be limited due to the moisture content's affect on transportation costs. This would make it difficult to recover material unless improved animal manure handling infrastructure and other feedstock handling infrastructure was in place to concentrate the materials or a facility were located very close to target areas. Food wastes and animal manures are often handled on-site or through a different system than the traditional municipal solid waste stream. Many of these generators are not used to paying tip fees to dispose of their wastes. However, future industry pressures (i.e. - in Animal Residuals for instance, concerns about "mad cow disease" could end up with new regulations that change current practices and provide for a huge increase in this raw material as feedstock) and regulatory pressures may provide new incentives to change current practices and provide for better recovery. For reasons like this, a range of potential capture rates for feedstock type, sectors, and region, based on a number of criteria used to evaluate the ability to recover a given animal manure or related biomass waste stream, including:

- Concentration of generators in a given geographic collection area
- Quantity of waste produced by individual generators (low, medium, high tonnage)
- Material handling equipment cost, load density and other material handling factors (moisture content, density-pounds per cubic yard, level of source separation)
- Current disposal practices and tip fees (competing end uses)
- Competing end uses (other composting, secondary production)
- Transportation type (truck, rail, pipeline, etc.) and costs
- New regulatory pressures and guidelines

These evaluation criteria need to be applied specifically to the target source of animal manure, biomass or other organic waste streams to determine a range of potential material availability rates and procurement costs (low=conservative estimate; medium=strong potential; high=aggressive, a mature program). These potential "capture" rates and cost scenarios make assumptions about potential *availability* of target material. Sustainable target tonnage can be derived by assessing the factors and developing a multiplier to total available tonnage, based on the potential for recovering each waste stream. In general, animal waste is considered the most difficult to recover and transport, and therefore the lowest multipliers are applied to this sector.

Animal Manure and Waste Management Infrastructure

South Carolina and the SERBEP region has a fairly well developed infrastructure that relies on a variety of systems and technologies for managing its waste. In order to successfully site, permit, and develop a BTA facility, Linpac will need to fit its plans into the current infrastructure.

Waste Management Infrastructure and Practices:

Competition for the solid waste stream, including the animal manure and biomass stream, occurs on a number of levels including different private sector service providers, "in-house" disposition methods, public sector versus private sector control, and via new technology developments and methods of handling and disposing of waste. An evaluation of waste type or format, and the waste generation infrastructure that exists to service the waste, can provide a more clear picture of where and how target organic material might be most available due to existing practices.

Animal manure is represented by swine, cattle and poultry production. The manure that these animals generate can take different forms and represent different handling problems. Manures can be generated in solid or liquid form. Typical composition of these materials is as follows:

- swine manure is typically generated as a liquid.
- cattle manure can be generated as a liquid or solid.
- poultry manure is typically generated a solid.

Land application and lagoon treatment of manure has been its historical disposal methodology. Land application occurs with animal production facilities that use outside 1ots or pastures, or with animal production facilities that have confined production facilities and produce either solid or liquid manure but use managed pasture or crop land application systems for disposal of the animal manure that is generated. Anaerobic lagoon treatment is used for liquid manures, particularly with confined swine production. These methodologies are currently "zero" cost disposal methods with regard to tip fee considerations, but are coming under increased scrutiny due to the environmental costs associated with them. This scrutiny may result in the industry facing new regulations or guidelines that require better disposal methods, which can add new process and treatment cost to the disposal, or require a service provider to assist in the disposal for a tip fee or equivalent charge.

To effectively handle and transport animal manure to a Biomass/Cogen facility for use as feedstock, the material typically has to be handled and prepared at the generation site to reduce shipping costs. The removal of water in liquid or semi-solid manure is key, as transporting the water can make the cost of transportation prohibitive. There are various technologies for dewatering manure:

- Gravity separation - a settling basin, concrete vessel or tank can be use to allow the solids to settle out of solution, whereby they can be periodically removed for disposal. This method can require a large area, a long settling time, and permits for basins or vessels.
- Drying - drying can be used to hasten the removal of the liquid. Drying can occur by "natural" methods under the right climatic conditions, or where the climate does not allow for natural drying, heat and air flow assisted systems can be used. Natural drying is not feasible in some areas of the country, while the energy required to assist in the drying can be cost prohibitive.
- Solidification - absorbent materials such as wood or cellulose fiber, yard waste or leaves, agricultural byproducts or compost can be used to thicken the liquid waste, which then can be transported in solid form. The solidification requires dry materials to be added to the mix, and will increase the amount of material that eventually needs to be disposed of. The solidification's increased volume can be both prohibitive or an opportunity depending on the cost of the dry materials used and their benefit to the re-use or disposal method.
- Mechanical separators - liquid manure can be dewatered using pumps, screens, filters, thickeners, and centrifugal separators and other devices to increase the solids content of the manure. This system can process large volumes quickly but can involve significant capital, operational and maintenance costs.

For the other four targeted biomass feedstocks (Animal Residuals, Food Manufacturing, Food Service and Pulp and Paper) landfilling has been the historically dominant disposal technology for their solid waste. Waste providers have hauling and disposal infrastructure in place, although recently alternative disposal methodologies have been used, including the following:

- Incineration - materials can be incinerated to reduce the volume and control pathogens.
- Composting (on-site and off-site) - composting is now well-established, and an increasing variety of large and small scale composting technologies are available in the marketplace. Around the country, food waste generators such as food manufacturing facilities, food processors, grocery stores, and restaurants are evaluating composting service providers, on-site composting, or small scale in-vessel compost systems.

- Land Application (on-site and off-site) - a large number of animal and food processors land apply at least part of their residuals. Permitting is done at a district level on a company-by-company basis dependent on the material composition and guidelines.
- Animal Feeding and Rendering - animal and food residuals are fed to animals in a variety of forms. Food that has not been in contact with or does not contain meat or meat by-products is exempt from federal regulation and can be fed to cattle and swine with no processing. Other animal and food waste must meet requirements of the 1980 Federal Swine Health Protection Act, which requires meat and meat by-products to be cooked at 212 degrees Fahrenheit for at least 30 minutes.
- Sewering (typical as liquid residuals) - where wastewater treatment facilities exist or sewer charges are not prohibitive, liquid residuals can be directly sewered or solid materials can be diluted and then added to sewer discharge for processing and disposal. In some cases this may even be desirable, for instance where a cellulose laden industrial stream can be combined with a nitrogen laden residential or commercial stream, thereby increasing the effectiveness of the biological activity and steps at the treatment facility.

Landfilling has evolved in recent decades to become somewhat more of an environmentally responsive method, as double composite liner systems, leak detection and similar modern landfill design techniques have been required through more stringent regulations. This has resulted in fewer but larger landfills that function more as regional disposal centers, often serving more than one state. Incineration technology grew significantly a couple of decades ago when landfill practices were first acknowledged to be inadequate to protect the environment. Market penetration by incineration systems was significant, especially in more urbanized areas. Regulatory pressures were then exerted both on landfills as well as on incinerators in order to protect the environment. Incineration systems were expanded to include energy recovery in order to improve the financial and environmental performance of these systems while still incorporating best available technology for emissions controls. As incineration has proven to be more expensive than anticipated, however, its share of the waste stream has fallen and landfilling has picked up most of the slack.

Waste Management Service Providers

Even a technology like the Biomass/Cogen's CCI/BTA process, which is assumed to be technically and economically feasible, still has many challenges in gaining market share within the State of South Carolina. These challenges primarily center on acquiring the required raw material stream. Generating material flow to the proposed facility in an environment that is effectively dominated in the animal manure case by current "zero" cost disposal parameters, or with regard to the other targeted biomass waste streams by large waste hauling/landfilling companies and/or very restrictive franchise requirements, requires careful selection and development of opportunities. Several factors in South Carolina have reinforced this situation. They include:

- Population - As seen previously the population in South Carolina and the adjoining SERBEP region has been consistently increasing in density in and around the urban and rural regions. This trend will effectively increase overall waste generation and also create opposition to landfill siting and CAFO disposal effects on water, land and air quality. Additionally, statewide geological characteristics may make it very difficult to site new landfills or CAFO sites without alternative disposal methods. Together, these factors make new landfill and CAFO development very expensive to pursue, difficult to site and costly to build and operate.

- Privatization - For the past decade, government agencies throughout the United States have struggled with tax base issues that frequently have resulted in privatizing what had previously been publicly operated waste management systems. Collection routes were sold, landfills and incinerators shut down, and the services turned over to private sector companies. Tougher environmental regulations, especially on landfills and incinerators, contributed to this push towards privatization. In some parts of the country this trend is already in advanced stages of maturity, whereas other areas are still exploring privatization options. Some believe this to be a cyclical trend that will eventually shift back to more public sector operations if private sector industry consolidation continues and if price increases result. As a private sector service provider, the Biomass/Cogen facility should be able to tap into this privatization trend towards higher pricing.

- Private Sector Rationalization - Reductions in the number of publicly operated disposal facilities contributed to a larger trend of consolidation of the collection and disposal system into a few private firms with large market shares across the country. Twenty years ago, Waste Management, Inc. was the first to start the trend, quickly followed by BFI, Laidlaw and a host of smaller players powerful in some regions of the country. These firms acquired smaller haulers and owners of single landfills and also grew by taking public programs. This trend entered its advanced stages when entities began to struggle with how to be profitable once the acquisition push began to slow.

- Bigger is Better - One natural consequence of the rationalization and privatization trends in the solid waste management environment is that the bigger companies acquire the smaller companies and larger private facilities generally replace the services provided by smaller public facilities. Frequently in the name of efficiency, efforts are consolidated, staffs reduced, and energies concentrated in focal areas. The larger waste management companies have pursued this approach quite aggressively in the landfilling business all over the country.

- Increasing Tip Fees - Ten years ago, many predicted landfill capacity shortages and steeply increasing landfill tipping fees were already showing up in the marketplace. The expected shortage was avoided as landfills secured additional capacity at a faster rate than projected and as recycling and composting diverted waste from landfills. The result has been that the remaining landfills have been competing for waste resulting in lower tipping fees. However, the consolidation and rationalization of the industry (as described above) is expected to reduce competition and result in a return to a gradual escalation in tipping fees. With the current pricing structure, it is unlikely that rates will drop for any significant amount of time.

- Private Waste Management Corporations Shifting Away from Recycling - One of the major impacts of the mergers is a re-evaluation by private sector waste haulers of their commitment to diversion programs (both recycling and composting). The leadership of both mega-companies maintains an operating philosophy that these recovery activities are not core businesses, that they impair company operational and financial performance, and that they should be divested. This leaves significant business opportunities for firms that are recycling, composting or reusing waste streams, particularly hard to handle waste streams like the targeted biomass residuals.

Ultimately, successful facility development requires that the developers take advantage of specific "holes" in the marketplace that allow the necessary organic waste stream to be brought to the proposed facility. This will occur if the Biomass/Cogen developers are able to exploit one or more of the following marketplace opportunities or "holes" in service.

- A large generator or industry that controls its own waste stream, and would see a benefit to the targeted waste stream being diverted from their landfill resource.

- A small hauler with no landfill resources that has the capability to direct its waste to a facility with preferential tip fees.

- A City or County that is trying to increase recycling by extracting organics from the waste stream either by source separated collection or removal of organics.

- A recycling facility that is trying to increase its throughput.

- A facility operator that has a stream that it can attract larger accounts.

All of these market forces build complexity into the process of siting and developing a Biomass/Cogen facility, and require proper engineering, permitting and business planning.

Waste Management Costs:

Waste management costs are typically the total costs associated with a municipality or to a company to handle, manage and dispose of their wastes. If the management of wastes involves only disposal of the wastes, then tipping fees at the landfill site are the major concern. Recognizing the long term environmental effects and costs of just disposing of wastes has led to government legislation to control how much and what type of wastes are to be permitted to be disposed of at disposal sites. This legislation, over the past decade, has been successful in reducing the quantities of waste being disposed of at landfill sites but has also increased waste management costs in some well regulated regional areas. The public sector as part of its regulatory responsibility typically has some responsibility to approve waste disposal sites for the private sector.

Tip Fee Structure

A critical factor for siting and successfully operating a Biomass/Cogen facility is the regional waste disposal tip fee structure. In some circumstances, tip fees in SERBEP urban areas can range as high as $80 - $95 per ton. Therefore, there are a number of regional opportunities available for exploitation. Landfill disposal costs provide one of the best summaries of the economic opportunity for siting a Biomass/Cogen facility in the state of South Carolina. Appendix M provides a list of South Carolina's Landfills and Material Recovery Facilities, as well as the top 25 landfills for the whole SERBEP region. Table 31 provides the average tipping fee for all landfills in a given area and the expected lowest competitive cost for waste hauling for distances from the Linpac Cowpens, South Carolina site. This average includes all the very small rural landfills or landfills permitted for very limited waste types. It is likely that the costs provided using this average is the lowest competitive cost, since these landfills likely cannot take the targeted Biomass/Cogen feedstocks.

Table 31: Average Landfill Tip Fees

Average Tip fee	SERBEP Only	Entire US
Within 300 miles	$25.72	$24.93
Within 600 miles	$27.47	$26.78
Within 900 miles	$27.06	$28.57

The average tip fee calculation for SERBEP and the entire United States is heavily influenced by the large number of rural landfills. Figure 7 provides the regional landfill tip fee mapping based on tip fee cost, showing the average tipping fee charged in regional areas.

Figure 7: Landfill Tipfees

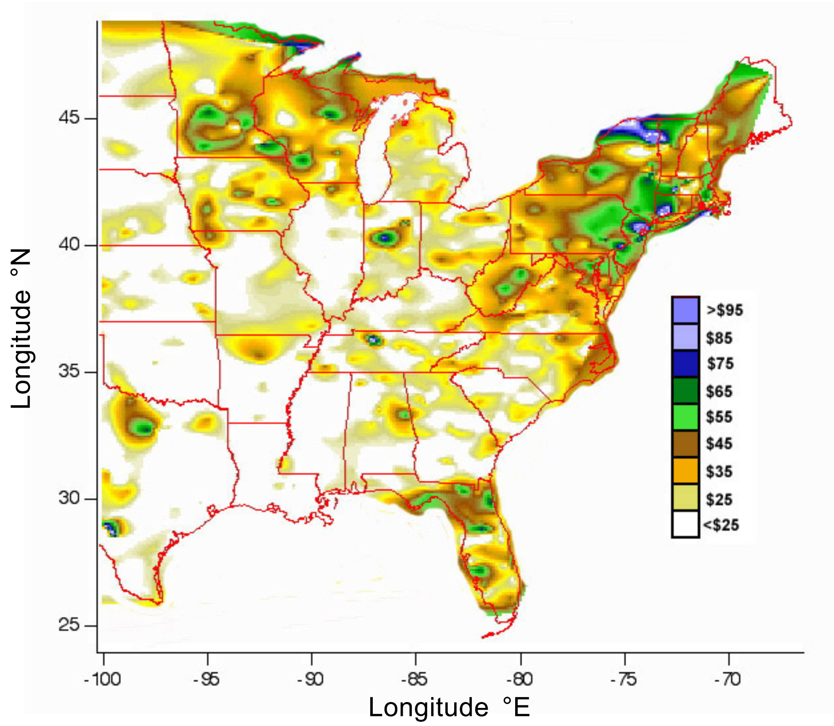


Table 32 provides the SERBEP region's State landfill tipping fee averages. The SERBEP state landfill tip fee averages are in the $20 - $43 per ton range. The average is developed on a State by State basis, where each State's tipping fee average counts as one figure no matter how many landfills are present in the State. Therefore, it represents the cost of a region. South Carolina and the adjoining SERBEP states, (North Carolina and Georgia) provide an average tip fee of $3.20, while the entire SERBEP States provide for an average tip fee of about $30 per ton. Based on this data it is reasonable to assume an adequate tip fee can be achieved. The Biomass/Cogen facility will actually be competitive with the higher cost landfills since they are the ones that can handle wet wastes and the targeted biomass residuals.

Table 32: SERBEP Region Tip Fees*

SERBEP State	Average Tipfee
Louisiana	$20.06
Mississippi	$20.26
Arkansas	$22.66
South Carolina	$27.27
Kentucky	$27.31
Missouri	$27.36
Alabama	$28.64
Tennessee	$28.97
North Carolina	$32.50
Virginia	$38.27
Florida	$42.83
Georgia	$42.83
West Virginia	$42.98
SC & Adjoining State Average	$34.20
SERBEP State Average	$30.92

**Note: Weighted average by State, with each State average counted equally*

Since Cowpens, South Carolina is at the northern edge of the SERBEP region, and since the Cowpens site is along the I-85 corridor, the potential to reach into higher tipping fee regions in northern Non SERBEP states exists. Table 33 provides the Non SERBEP region's State landfill tipping fee averages. These are states that can reasonably be assumed to within waste hauling range. This data suggests that tipping fees at an average of $40 per ton are reasonable to achieve, with higher tip fees when competition against landfills that can dispose of the targeted wet biomass residuals is realized.

Table 33: Non SERBEP Region Tip Fees*

Non SERBEP States	Average Tipfee
NEW JERSEY	$61.76
NEW YORK	$56.34
PENNSYLVANIA	$49.12
MICHIGAN	$31.98
INDIANA	$30.73
OHIO	$30.39
ILLINOIS	$28.50
State Regional Average	$41.26

**Note: Weighted average by State, with each State average counted equally*

Recycling of some of the waste stream has always taken place especially as higher value items like metal and some types of paper have been "cherry picked" on the trash routes. This core recycling activity led to diversions in the 10 to 15 percent range nationwide. Only in the last two decades has recycling re-use moved beyond these economic constraints and reached towards the 30 percent level as more innovative ways have been found to 1) divert material from the waste stream, 2) pay for the additional costs of that diversion; and 3) use the material as a feedstock in new product manufacture. Parallel trends developed in organics management as more and more sophisticated systems have been developed to divert the compostable waste stream and process it into marketable organic products.

Current trends show recycling/re-use's market share to be holding its own or dropping slightly. Recycling/re-use will be taking market share primarily from landfilling with a much smaller amount from incineration or other disposal methods. Linpac CCI/BTA technology, with projected tipping fees that are at or below current and future regional landfill tipping fee costs, will fare well on an economic basis in this market share competition. The Biomass/Cogen facility's capability to take problematic biomass wastes, such as wet or liquid wastes, should increase the recovery of regional animal manure and biomass waste. To successfully capture necessary waste streams this economic advantage must be matched with clever raw material collection strategies and an aggressive raw material procurement program that will allow the lower tipfee to become a deciding factor over the strong infrastructural bias in favor of the status quo.

Energy Market Preliminary Assessment

The energy markets represented by natural gas and electricity have been very volatile lately, with prices increasing dramatically in recent quarters in many regional areas across the nation. Natural gas prices have spiked in many areas of the country, and have hit the Pulp and Paper Industry particularly hard. Many mills that are dependent on natural gas to generate steam and/or electricity have had to shut down due to energy costs eroding the margins and sustainability of the mill. The ongoing California energy crisis, as well as forecasted summer electrical energy shortages in the eastern New York and some other eastern United States regions could be an indication of the need to develop alternate energy sources, such as the Biomass/Cogen project.

The Linpac Biomass/Cogen project's main focus is the production of biogas to replace natural gas. Currently Linpac uses natural gas to produce steam to the linerboard mill operations. Natural gas and electrical production are intertwined due to the natural gas being the most environmentally friendly fuel for fast paced electric power facility permitting, and for use for in electric peak power generation or industrial generation facilities. Appendix N provides Department of Energy (DOE) consumption forecast figures for natural gas. Note that the consumption of natural gas for electricity generators is projected to grow dramatically. The Biomass/Cogen facility has three basic scenarios or options for use with regard to the biogas, and as it relates to the energy markets:

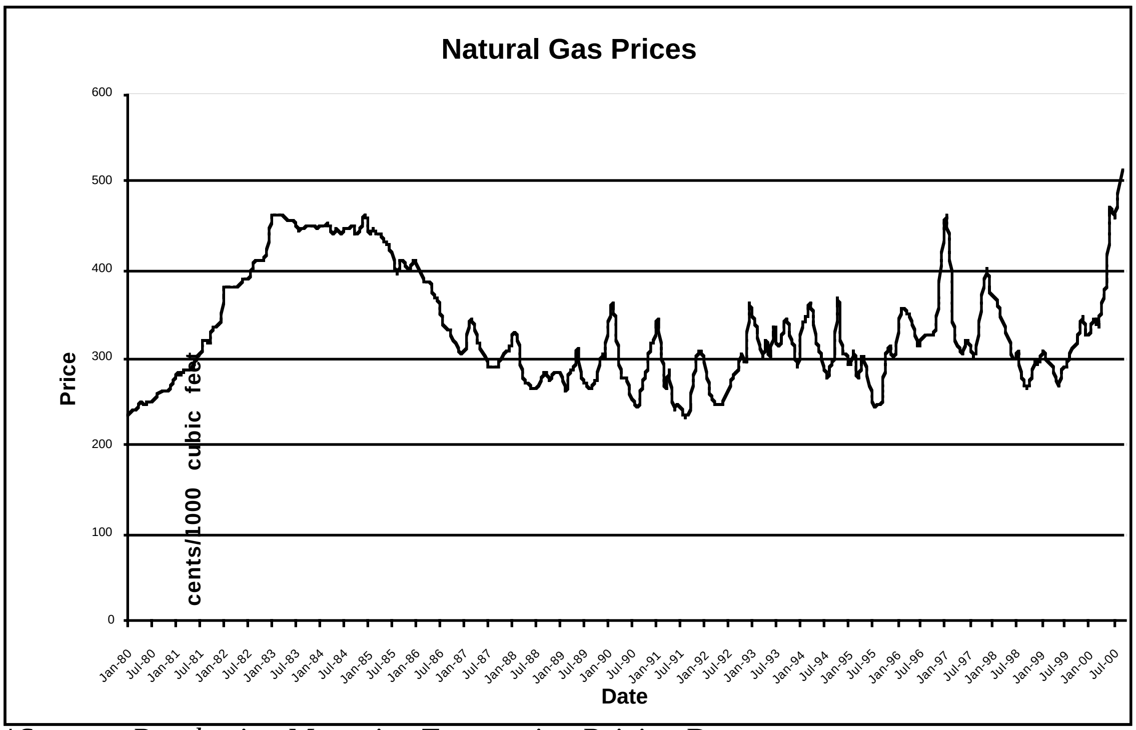
- produce biogas as a substitute for natural gas in current boiler operations.
- produce biogas for cogeneration, supplying steam and electricity to the mill.
- produce biogas for cogeneration, supplying steam to the mill end electricity to the grid.

The opportunity to use cogeneration technology to produce biogas for natural gas substitution, or for in a cogeneration mode to produce both steam and electricity, means a preliminary assessment of both the natural gas and electric markets is prudent. The natural gas pricing is expected to remain at a high level over the long term, even with expected new natural gas production and capacity becoming available.

Natural Gas Markets

The price of natural gas has been climbing to new pricing highs in recent months. This rise in the price of natural gas has been detrimental to the competitiveness of industrial sites dependent on natural gas for energy requirements, and has significantly increased utility bills to residential and commercial applications. Figure 8 provides a graph of the historical fluctuations in natural gas pricing, showing the pricing increases.

Figure 8: Historical Natural Gas Pricing



**Source: Purchasing Magazine Transaction Pricing Data*

The price increases have been due to increased demand for natural gas for heavy industrial applications to produce on site steam and/or electricity, increased utility electrical generation applications required by permitting concerns or for peak power facilities use, and increased commercial and residential use. As shown in Table 34, the natural gas pricing increased over 100% in the last 8 quarters.

Table 34: Natural Gas Recent Quarterly Transaction Pricing

Year & Quarter	1999 Q1	1999 Q2	1999 Q3	1999 Q4	2000 Q1	2000 Q2	2000 Q3	2000 Q4
Natural Gas Price (cents/mcf)	231	235	240	266	357	391	407	502

**Source: Purchasing.com*

The natural gas pricing is expected to remain at a high level over the long term, even with expected new natural gas production and capacity becoming available. Table 35 provides forecasted pricing for natural gas for the next 8 quarters, showing the pricing remaining high.

Table 35: Natural Gas Forecast Quarterly Transaction Pricing

Year & Quarter	2001 Q1	2001 Q2	2001 Q3	2001 Q4	2002 Q1	2002 Q2	2002 Q3	2002 Q4
Natural Gas Price (cents/mcf)	552	480	452	468	533	475	498	522

**Source: Purchasing.com*

Appendix O provides the SERBEP State's natural gas pricing data for the DOE, with natural gas pricing data for industrial, commercial and other sectors. Ranking the States by highest to lowest cost, Table 36 shows that the State of South Carolina has industrial natural gas costs that are ranked 9th out of 13, and commercial gas costs that are ranked 3rd out of 13.

Table 36: SERBEP State Natural Gas Cost Rankings
(Highest to Lowest Cost)

Commercial	Industrial
D. C.	D. C.
Alabama	Missouri
South Carolina	Florida
Florida	North Carolina
West Virginia	Tennessee
North Carolina	Arkansas
Tennessee	Alabama
Louisiana	Georgia
Missouri	South Carolina
Arkansas	Kentucky
Kentucky	Mississippi
Mississippi	West Virginia
Georgia	Louisiana

South Carolina tends to have higher than average natural gas costs compared to other SERBEP states, and thus represents a good regional area for placement of an anaerobic digestion facility to produce biogas to substitute for natural gas. Since the Biomass/Cogen facility will produce biogas, which has between 65% and 70% methane, an 'apples to apples' comparison of natural gas pricing to biogas pricing reflecting each gas source's $/Btu cost is required. To achieve this, it is important to provide an indication of what the typical regional pricing would be in dekatherms (DT) to reflect the actual cost per Btu. Table 37 provides natural gas costs in DT based on rates that reflect some typical residential, commercial and industrial rates.

Table 37: Typical Natural Gas Pricing for South Carolina

Rate	Residential	Commercial	Industrial
Natural Gas Price target and range (dollar/dekatherm)	target: $12.260 range: $12.910 to $11.600	target: $12.230 range: $12.980 to $11.660	target: $11.148 range: na

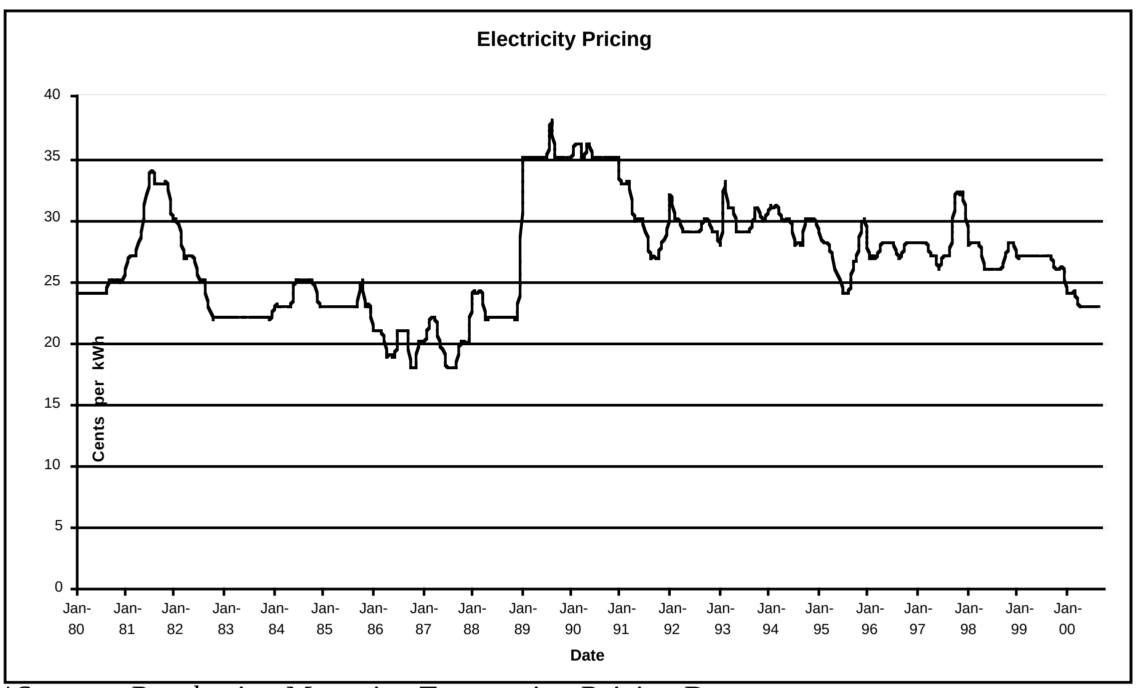
**Source: South Carolina Gas & Electric Rate Sheets*

The revenue value placed on the natural gas via the current and expected future pricing levels above tentatively represents a good biogas pricing basis for development of a Biomass/Cogen facility. The biogas produced would be used by the Linpac mill for substitution of natural gas and a cost savings against the expected natural gas pricing.

Electricity Markets

The opportunity to sell excess electrical power to regional utilities or the grid represents a good alternative for the Biomass/Cogen facility. Appendix P provides DOE national and SERBEP electricity generation data, with graphical representation of the national electrical generation service grid framework as well as state by state averages for electricity cost in cents per kilowatt hour (cents/kwh). The electrical generation utility service across the nation is divided into three regional interconnections or grids. South Carolina is part of the Eastern Interconnection, and has some of the lowest electrical energy costs in the nation as well as in the SERBEP region. Figure 9 shows the average national transaction pricing of electricity.

Figure 9: Historical Electricity Pricing



**Source: Purchasing Magazine Transaction Pricing Data*

Although the average national price has been dropping, in certain regional areas (i.e. California, East Coast) the price has risen sharply. Recent national averages have been relatively stable, with only slight increases in price. Table 38 provides recent electrical pricing by quarter.

Table 38: Electricity Recent Quarterly Transaction Pricing

Year & Quarter	1999 Q1	1999 Q2	1999 Q3	1999 Q4	2000 Q1	2000 Q2	2000 Q3	2000 Q4
Electricity Price (cents/kwh)	4.38	4.25	4.31	4.14	4.16	4.40	4.80	4.72

**Source: Purchasing.com*

Generally, the expected forecast is for electrical pricing to remain stable over the long term. Table 39 provides forecasted pricing by quarter through 2002.

Table 39: Electricity Forecast Quarterly Transaction Pricing

Year & Quarter	2001 Q1	2001 Q2	2001 Q3	2001 Q4	2002 Q1	2002 Q2	2002 Q3	2002 Q4
Electricity Price (cents/kwh)	5.19	4,52	4,25	4,40	5.02	4.46	4.68	4.91

**Source: Purchasing.com*

Appendix P provides DOE electricity pricing data for all SERBEP States for residential, commercial and industrial sectors. Table 40 shows that South Carolina rates as the 5th out or 14 highest SERBEP State with regard to residential electricity pricing, the 7th out or 14 highest SERBEP State with regard to commercial electricity pricing, and the 13th out or 14 SERBEP State with regard to industrial pricing, and 12th out of 14 for all sectors. South Carolina industrial customers, such as Linpac, have comparatively low electrical energy costs. This would indicate that substitution of Linpac's current electrical supply with the Biomass/Cogen generated electricity may not be as advantageous as providing it to the grid.

Table 40: SERBEP State Electricity Cost Rankings by Sector (Highest to Lowest Cost)

Residential	Commercial	Industrial	All Sectors
Louisiana	Louisiana	Louisiana	Louisiana
North Carolina	Dist. of Columbia	Dist. of Columbia	Dist. of Columbia
Florida	Georgia	Florida	Florida
Georgia	North Carolina	North Carolina	North Carolina
South Carolina	Mississippi	Tennessee	Georgia
Virginia	Florida	Mississippi	Mississippi
Arkansas	South Carolina	Arkansas	Virginia
Mississippi	Tennessee	Georgia	Arkansas
Dist. of Columbia	Alabama	Alabama	Tennessee
Alabama	Arkansas	Virginia	Missouri
Missouri	Virginia	West Virginia	Alabama
Tennessee	West Virginia	Missouri	South Carolina
West Virginia	Missouri	South Carolina	West Virginia
Kentucky	Kentucky	Kentucky	Kentucky

The above provide for a reasonable assumption that a cogeneration unit to produce electricity would have a well placed market. The likelihood of being able to sell excess electricity back to the utility and grid is increased by the fact that the electricity produce would be "green power", and in certain instance command a premium price.

It is reasonable to expect that electrical power generated from biogas could be sold at a premium as “green energy” to the power grid. One possibility is for the electric utility servicing the area in which the electricity is generated to buy the electricity and market it as “green energy.” However, it may be possible to sell energy directly to a utility in a higher demand location, such as New York, using only the access to the grid provided by the local utility, resulting in a higher selling price for the electricity. South Carolina tends to have low electricity prices, by national standards, so sale of electricity locally on the grid would not be at a premium price, unless the demand for “green energy” is quite high.

Depending on the stability of the energy supply from the biogas plant to the grid and the amount and quality of the power, the biogas power supplier and the utility would come to agreement on the purchase price for the electricity. The Public Utilities Regulatory Policies Act (PURPA) and its successors are intended to ensure that small electricity generators and renewable power sources get advantageous pricing for their power. These policies are not yet built into the South Carolina regulatory structure, but regulators are aware of PURPA. Randy Watts of the Public Service Commission, Utilities Department indicated that his department would approve rates agreed upon by the biogas power generator and purchasing utility. Alternatively, there is potential for direct sale of electricity or steam to nearby businesses or industry in the biogas plant area.

Factors Affecting Site Electrical Power Generation

The Biomass/Cogen facility size target per electricity generation capability, based on the CCI Newmarket Ontario facility as a template, is a 4 - 5 MW facility. The future facility size is limited by or dependent on the following design basis criteria and market parameters:

- biomass raw material feedstock availability
- facility scale issues implementing the technology and operations
- regional markets for compost and other facility by-products
- linerboard mill natural gas and electrical supply requirements
- offsite electrical sales to utilities or the grid, particularly green power packages
- local industrial or commercial market development of industrial parks

The increase in facility sizing as it relates to available offsite electrical markets is best evaluated via its utility growth and their dependence on the expected growth in the electrical demand in the regional area. Secondarily, the potential for state or regional deregulation effects and/or green power incentive programs or market development that are already in place or may develop will have an effect on facility sizing.

Regional Utility Service Providers Growth:

South Carolina and the adjoining SERBEP states of North Carolina and Georgia are along the I-85 corridor, an area that has shown tremendous growth in recent years. This has provided for large electrical capability and generation needs with good electricity demand growth. Table 41 provides the South Carolina, North Carolina and Georgia electricity capability and generation data.

Table 41: South Carolina Regional Electricity Capability and Generation

Parameter/State	South Carolina	North Carolina	Georgia
Capability(MW)	18,116	22,845	25,082
Generation((MWh)	87,244,314	121,371,988	115,327,447
Annual Growth Rate [1988-98](%)	1.9	0.5	2.0

The regional area electricity services are provided by various utilities. Table 42 provides a listing of the major regional utilities based on their retail sales volume

Table 42: Utility Retail Sales Revenue 1998 (Million Dollars)

Utility/State	South Carolina	North Carolina	Georgia
Duke Energy Corp.	1,070	2,963	
South Carolina Electric & Gas	1,128		
Carolina Power & Light	415	2,117	
Virginia Electric & Power		204	
Georgia Power Company			4298

The major facilities serving South Carolina are Duke Energy and South Carolina Electric and Gas. Tables 43 and 44 provide the forecasted growth for each of these utilities.

Table 43: Duke Energy Corporation Electrical Market Forecast

Year	Peak MW Summer	Peak MW Winter	Annual Energy MWH	Annual % Change
1999	18,693	16,484	98,016,330	
2000	18,335	15,866	98,568,300	0.6
2001	18,737	16,162	100,962,420	2.4
2002	19,122	16,399	103,230,280	2.2
2003	19,543	16,658	105,506,560	2.2
2004	19,951	16,934	107,757,910	2.1
2005	20,156	17,160	109,703,850	1.8
2006	20,540	17,431	111,912,760	2.0
2007	20,946	17,711	114,092,770	1.9
2008	21,364	17,954	116,126,390	1.8

Table 44: South Carolina Electric and Gas Electrical Market Forecast

Year	Peak MW Summer	Peak MW Winter	Annual Energy MWH	Annual % Change
2000	4,288	4,063	21,934,000	N/A
2001	4,400	4,184	22,588,000	2.9
2002	4,494	4,282	23,120,000	2.3
2003	4,599	4,382	23,663,000	2.3
2004	4,684	4,463	24,096,000	1.8
2005	4,791	4,563	24,648,000	2.2
2006	4,883	4,652	25,129,000	1.9
2007	4,968	4,733	25,572,000	1.7
2008	5,069	4,832	26,106,000	2.0
2009	5,175	4,935	26,667,000	2.1

The growth rates of the region and the utilities show that excess electricity could readily be absorbed by the current and expected markets.

Deregulation Effects:

Deregulation will significantly affect the energy markets. Under the traditional method of regulation a utility's rate of return was limited. Out of a belief that this system did not provide sufficient incentive for the efficient operation of utilities, regulators at the state and federal level began to move the system to a more competitive structure. Utilities are being broken up into generators, distributors and transmitters of electricity. Changes are effecting every aspect of the industry and creating new types of players in the energy market. Investor-owned utilities are reducing staff, reorganizing, and in some cases, expanding to remain competitive. Publicly owned utilities, though typically with lower costs, are also preparing for increased competition. New entities called Power Marketers are buying and reselling electric energy, transmission and other services. They are still small but are growing fast.

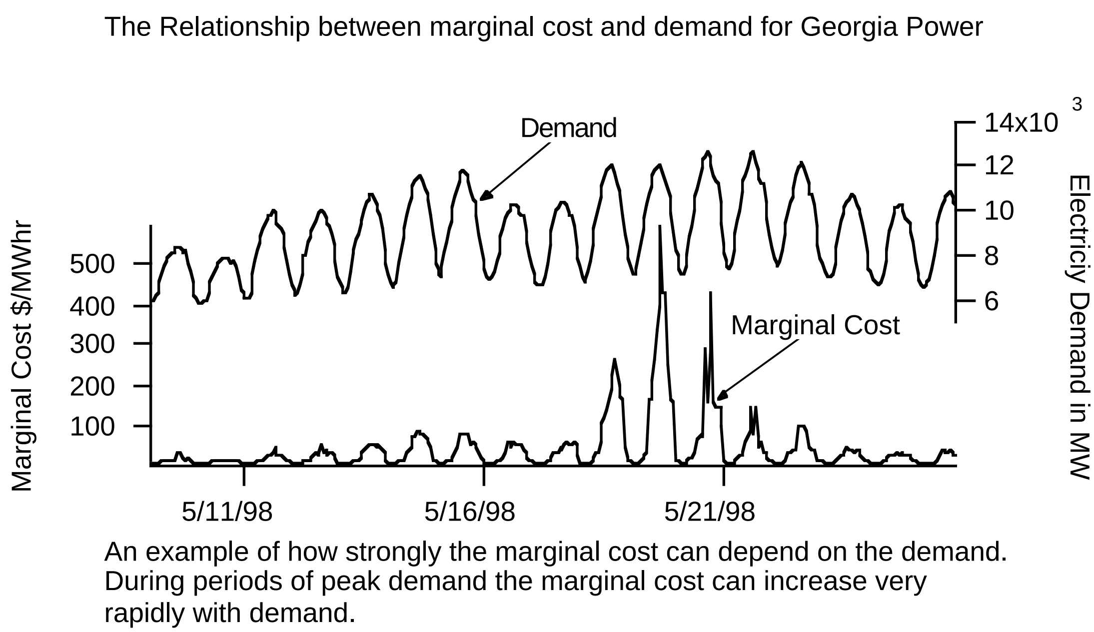
South Carolina currently has relatively low energy costs compared to the rest of the country. In 1998 the average cost of electricity for the U. S. was 6.7 cents per kilowatt hour. South Carolina businesses should not expect to continue to enjoy such low energy costs. In addition, South Carolina and regional SERBEP generators can expect to see price increases as deregulation proceeds. Several additional opportunities exist for Green Electricity generated at cogeneration facilities such as a Biomass/Cogen Facility. Facilities meeting criteria set forth by FERC qualify under the Public Utility Regulatory Policies Act (PURPA). Such utilities are required to buy back their extra electricity at the avoided cost. The potential to provide electrical energy to the grid improved with the use of a cogeneration facility, particularly if the Biomass/Cogen facility is a Cogenerator Qualifying Facility, as follows:

> Cogenerator Qualifying Facility (Cogen QF): (Facilities that) sequentially produce electric energy and another form of energy, such as heat or steam, using the same fuel source; are qualified under the Public Utility Regulatory Policies Act (PURPA) by meeting certain criteria set forth by FERC and, therefore, are guaranteed that utilities will purchase their output.

There are also new ways to buy, sell and market electric power. Spot markets have been set up and are providing an alternative source for wholesale electricity. At the retail level the marketing of "Green Power" is rapidly growing, particularly in the states that are farthest ahead in their efforts to deregulate. All of these will exert forces on the market. The cost of electricity currently varies by almost 260% across the country and differences greater that 200% exist between nearby states. In a competitive market place large differences in price over short distances will attract the interest of both buyers and sellers of electric power.

Those costs vary widely within the South Carolina, North Carolina, and Georgia region. Peak power demand also is becoming a significant factor in some areas, particularly due to some seasonal effects. Based on available data, in 1999 the hourly average marginal costs for Duke Energy and South Carolina Electric were estimated at $14.5 and $20.8 per megawatt hour respectively. In 1998 (the latest year for which data is available) the hourly average marginal cost to generate a megawatt hour of energy for Georgia Power was estimated at $27.3. Figure 10 shows an example of the relationship between peak demand and marginal cost.

Figure 10: Peak Power Demand and Marginal Cost Example



In addition to varying across the region, the cost varies dramatically throughout the year. The cost varies because the demand varies. Typically for the Southeast the average electricity demand is only about 60% of the peak demand. During periods of peak demand the ability of the system to supply energy can be severely taxed. At these times utilities are forced to operate all of their facilities, including the least efficient ones, and may be forced to buy electricity on the wholesale market right at the time that price is the highest. In 1999 during just a handful of days the marginal cost of power at Duke energy spiked to $30, $50 and $100 per MWhr. If Duke Power had additional resources available to supply their extra needs at their average marginal cost for these periods in 1999 they could have saved millions of dollars. This peak power need could represent an opportunity for the Biomass/Cogen facility.

The biomass cogeneration facility need not only sell power to the grid during peak times. The previous example was only to demonstrate the dramatic relationship between marginal cost and peak demand. In order to be profitable a facility need only generate electricity below the market rate and have a nearby buyer. The marketing of the Biomass/Cogen energy generated from biomass in a cogeneration facility may even bring a premium if the "green power" energy market continues to develop as it has.

Renewable Energy Policy Incentives:

Across the nation, new policy is being developed and implemented to promote renewable energy and green power generation. There are four main policy approaches to encouraging renewable energy development and these act as incentives for green power packages:

Renewable Portfolio Standards: Renewable Portfolio Standards (RPS) are a mechanism for creating demand. Utilities are required to have a minimum amount of renewable energy generation capacity within their systems. Ten states have adopted renewable electricity standards that could lead to the development of 5,450 MW of new renewables by 2012 and support 3,600 MW already in place. Combined, this capacity will generate enough clean power to meet the electricity needs of 5.7 million typical (nonelectric heating) US homes.

Renewable Electricity Funds: Renewable Electricity Funds (REF) provide predictable funding sources for the development of renewable energy sources. Utilities are required to contribute to a fund that promotes renewable energy. Thirteen states have established renewable energy funds that will collect an estimated $2 billion over the next 15 years and could lead to the development of 1,100 MW of new renewables by 2012. (Because some states have both renewable standards and funds, the funds are expected to add about 700 MW in addition to the 5,450 MW supported by the standards.)

Net Metering: Net Metering allows customer-generators to sell back electricity to the utility when they are generating more than they need. This is, in essence, using the grid to "store" electricity. Thirty states have adopted net metering policies, which makes it easier and more affordable for customers to generate their own power from renewable energy systems.

Disclosure of Fuel and Emissions: Disclosure of the fuel mix on electricity bills helps educate the public and create demand for green pricing programs. Fifteen states have required electricity providers to disclose on electricity bills the fuel mix and environmental impacts of their products, to increase consumer awareness and promote informed customer choice. In addition, power companies in 22 states now offer customers a green power choice. To date, green power purchases have resulted in 112 MW of new renewables, with another 107 MW in the planning stages.

Nationally, only a few states have adopted all four of these policies, while 11 states have adopted 3 of the 4. Only 19 states have failed to adopted any of these four policies and more than half of those states are in the SERBEP region.

SERBEP States Renewable Energy Policy:

The SERBEP region is behind the nation in renewable energy policy. However, this may represent a future opportunity as SERBEP States catch up with national trends. Table 45 provides a summary of the renewable energy programs adopted in the SERBEP States.

Table 45: A Summary of Renewable Energy Policy Adopted by SERBEP States

Type	RPS	REF	Net Metering	Disclosure
Alabama	No	No	No	No
Arkansas	No	No	No	No
DC	No	No	Yes	No
Florida	No	No	2 local	No
Georgia	No	No	No	No
Kentucky	No	No	No	No
Louisiana	No	No	No	No
Mississippi	No	No	No	No
Missouri	No	No	No	No
N. Carolina	No	No	No	No
S. Carolina	No	No	No	No
Tennessee	No	No	No	No
Virginia	No	No	Yes	No
West Virginia	No	No	No	No
Other States	11	15	31	11

All of the programs in the SERBEP region are net metering programs. Both Florida Net metering programs are local. One is in Jacksonville and the other is in New Smyrna Beach. The Jacksonville utility will buy back customer generated electricity. Customers are required to purchase (from the utility) a second meter to measure energy deliveries to the utility. In New Smyrna Beach Utilities Commission will allow customer-generators to connect their own net metering equipment to the grid as long as it meets certain industry standards. District of Columbia also has a Net Metering program that allows residential and commercial customers to connect renewables, fuel cells, and microturbine systems up to the electrical grid. Each generation system is limited to 100 kW in capacity.

In Virginia net metering is available to both residential and commercial customers. Systems that are intended to offset the consumer's electricity requirements through solar, wind, or hydropower are eligible. Systems must meet industrial standards for electrical equipment. A standard bi-directional kilowatt-hour meter is allowed. Excess generation may accumulate for up to a year. Any remaining credit at the end of the year is granted to the utility.

Non SERBEP States Case Study Examples

Much can be learned from non SERBEP states with regard to programs that promote renewable energy. During the past few years, many states have shown interest in using new renewable energy sources -- wind, solar, geothermal, and biomass power. Over one-third of the states have made commitments that will increase the use of these cleaner energy sources in the United States by an estimated 6,200 megawatts (MW) -- 40 percent over 1997 levels. This new development will provide enough clean power to meet the entire electricity needs of 4 million homes and reduce as much carbon dioxide -- the main greenhouse gas implicated in global warming -- as taking 3.4 million cars off the road or planting 816 million trees covering an area almost the size of Maryland and Delaware combined.

Most states have made these commitments as part of a package to restructure the electricity industry to help clean up the environment while increasing competition. A few states, however, have taken major steps to increase renewables outside of restructuring. States have adopted four main approaches to promoting renewable electricity development. While the potential impact and effectiveness of each policy varies greatly from state to state, the most important policies are renewable-electricity standards and funds. These policies create renewable energy markets and provide measurable commitments to renewables development. But net metering, disclosure, and customer choice of renewable electricity have also all been important in overcoming particular market barriers to increasing renewables.

Some states have adopted programs that address all four of these areas but these few states do not have the corner on renewable policy advances. Only three states (Connecticut, Massachusetts, and New Jersey) have adopted all four of the policies, while 12 other states have adopted three of the four. In contrast, 20 states have failed to adopt any of the key policies for supporting renewables, and 10 states have only adopted one policy (net metering). This number includes eight states (Arizona, Arkansas, Delaware, Michigan, New Hampshire, Oklahoma, Vermont, and Virginia) that have missed an opportunity to provide support for renewables as part of electricity restructuring. A wide range of programs exists in states in the East Coast, the Heartland and the West. For example:

> Massachusetts - Massachusetts is one of the states with the most renewable electricity sold (as a share of total). Massachusetts has adopted policies to encourage renewables in all four of the main categories. As part of electric utility deregulation Massachusetts adopted the outline of a Renewables Portfolio Standard (Chapter 164 of the Acts of 1997). The Division of Energy Resources (DOER) just completed a series of 12 meetings to work on the policy details.
>
> Connecticut - Connecticut has some of the highest long-term funding (per kilowatt-hour) for renewables. One mechanism for that funding is a very strong public benefits program. Over the next five years this program will generate almost $120 million through a per kwh charge (increasing from 0.5 to 1 mill/kwh over the next five years). There are very few restrictions on the uses of this money. The law, CT Public Act No. 98-28, Section 44(c) includes "grants, direct or equity investments, contracts or other actions which support research, development, manufacture, commercialization, deployment and installation of renewable energy technologies, and actions which expand the expertise of individuals, businesses and lending institutions with regard to renewable energy technologies."
>
> Texas - Texas is creating one of the nations largest Renewables Markets which is driven by the Renewables Energy Mandate Rule. The Mandate calls for 2,000 MW of new renewables to be installed by 2009. Beginning in 2002 each retailer will be required to meet a portion of this goal. Retailers may either generate electricity from renewable sources or purchase Renewable Energy Credits (REC) from other retailers that have RECs for sale. Qualifying electricity must be both generated and metered in Texas. For details see Section 39.904 of Texas Utilities Code; PUCT Substantive Rule 25.173.
>
> Ohio - Ohio has one of the most progressive Net Metering Policies in the nation. In 1999 Ohio passed legislation (Ohio Legislature, SB 3) as part of the electric utility restructuring bill that allowed customer-generators to sell electricity back to the utilities. The electricity must come from a qualifying source (most renewables) and be intended to offset the customers' electricity needs. The customer-generator's net metering equipment is only required to meet standard electrical safety requirements. Utilities are not allowed to require additional safety standards.
>
> Illinois - Illinois provides an example of one of the nation's strongest Disclosure Rules (1997 House Bill 362). Each customer's electric bill includes a pie chart showing the percentage of electricity supplied by source (i.e. biomass, coal, hydro, natural gas, nuclear, oil, solar, wind, other). In addition, the utilities have to report emissions (i.e. carbon dioxide, nitrous oxide, sulfur dioxide, and nuclear waste).
>
> Iowa - Iowa has made one of the strongest commitments to renewables outside of electric utility restructuring legislation (Code of Iowa 476.41-476.45). The Iowa Utilities Board requires the state's three utilities to purchase a total of 105 MW of renewable and small hydropower. Currently the majority of this requirement is being met with wind and biomass generation.

Minnesota - Minnesota has made the biggest commitment to Biomass. A state grant program (MS2000 41A.09) provides up to $37 million for biomass and alternative fuels. Industries can receive 1.5 cent/kwh or up to 20 cents/gallon from the grant program.

The examples of non SERBEP states policies, and the successful renewable energy programs they promote, could become key policy components for SERBEP State who desire to sponsor renewable energy programs in the future. Many of the SERBEP states have draft policy that is being evaluated and reviewed for use based on the above models. This new policy activity could provide new incentives to renewable energy and green power generation such as that represented by the Biomass/Cogen facility.

Project Financial Analysis Estimates

The workscope involved providing a preliminary evaluation of the business opportunity, using a ten year cash flow (TYCF) format for financial analysis and evaluation. Preliminary business planning was performed to define the key business and operational parameters to use in the analysis, as well as future business plan and engineering execution plan requirements. The preliminary financial analysis was based on four options for the Biomass/Cogen facility. Each option was based on a 165,000 tons per year anaerobic digestion facility as the biogas producing component of the Biomass/Cogen facility, with various options for the energy unit system to convert the biogas into electricity and/or steam.

Project Options Base Case Financial Analysis Estimates

Appendix Q provides the ten-year cash flow (TYCF) financial analysis results for Option 1 as an example of the financial analysis format. The financial analysis for options 2, 3 and 4 was accomplished using the same TYCF format. The TYCF format provides for all the assumptions and cost areas, and estimates various cash flow and return on investment parameters. The financial analysis is based on previous work that was done to show that there was ample feedstock available in the $30 - $50 tip fee range, and as per the above capitals cost summaries that reasonable capital costs could be obtained for each of the options. The TYCF analysis used the following key revenue assumptions from the results of previous work:

- Total Production Tons = 165,200 tons per year
- Average Tip Fee per Ton = $ 36.25
- Biogas Price per DekaTherm (DT) = $ 3.00
- Average Compost Price per Ton = $21.50

These key revenue assumptions were used with operational cost parameters that were developed in the conceptual engineering and technical evaluation work, and refined against Linpac Paper operational cost benchmarks(does this describe the operational cost parameters or the evaluation work? Tables 46, 47, 48 and 49 below provide the Financial Analysis Estimate Summaries for Options 1, 2, 3 and 4, respectively. These summaries provide the key financial analysis results for each option.

Table 46: Option 1 Financial Estimate Summary

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$26,206,481
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$28,067,141
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$1,569,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$3,102,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,589,478
Total Operational Cost	$5,015,027
Net Revenue	$4,026,227
EBITA	$5,319,727
Post Tax Internal Rate of Return (IRR)	12%
Pre Tax Internal Rate of Return (IRR)	14%
Senior Debt Service Coverage Ratio	1.50

Table 47: Option 2 Financial Estimate Summary

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$29,940,981
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$32,066,791
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$2,145,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$3,678,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,634,292
Total Operational Cost	$5,059,841
Net Revenue	$4,557,413
EBITA	$5,850,913
Post Tax Internal Rate of Return (IRR)	12%
Pre Tax Internal Rate of Return (IRR)	14%
Senior Debt Service Coverage Ratio	1.46

Table 48: Option 3 Financial Estimate Summary

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$32,007,402
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$34,279,928
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$2,145,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$3,678,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,659,089
Total Operational Cost	$5,084,638
Net Revenue	$4,532,616
EBITA	$5,826,116
Post Tax Internal Rate of Return (IRR)	12%
Pre Tax Internal Rate of Return (IRR)	13%
Senior Debt Service Coverage Ratio	1.36

Table 49: Option 4 Financial Estimate Summary

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$37,976,481
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$40,672,811
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$4,211,198
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$5,744,254
Variable Cost	$2,425,549
Semi Variable Cost	$2,730,718
Total Operational Cost	$5,156,267
Net Revenue	$6,526,487
EBITA	$7,819,987
Post Tax Internal Rate of Return (IRR)	14%
Pre Tax Internal Rate of Return (IRR)	16%
Senior Debt Service Coverage Ratio	1.57

Each of the base case financial analysis summaries for the various options provides for a positive post tax IRR estimate in the teens, providing a preliminary indication that each of the project options would be economically viable. Option 4, the gas combustion turbine, appears to have the strongest IRR. However, the fact that the base case provides for an IRR that is only in the teens may not be high enough to clear corporate hurdles for IRR based on the project risks.

Project Options Sensitivities Financial Analysis Estimates

The Biomass/Cogen project has five major sources of revenue: 1) tip fees; 2) compost; 3) biogas; 4) electricity; and 5) steam. Three of these major sources of revenue are stategic to the project because they have greater risk associated with them. These are the tip fees, compost and biogas revenues. Using the base case scenario for each of the options, post tax IRR was calculated for typical pricing ranges for the biogas, compost and tip fees. Tables 50, 51 and 52 show the sensitivity financial analysis for biogas, compost and tip fee pricing ranges.

Table 50: Sensitivity Financial Analysis Based on Biogas Price Changes

Biogas Price ($/DT)	Base	$1.00	$2.00	$3.00	$4.00	$5.00	$6.00	$7.00
Option 1: Post Tax IRR	12%	9%	11%	12%	14%	15%	16%	18%
Option 2: Post Tax IRR	12%	10%	11%	12%	13%	15%	16%	17%
Option 3: Post Tax IRR	12%	9%	10%	12%	13%	14%	15%	16%
Option 4: Post Tax IRR	14%	12%	13%	14%	15%	16%	17%	18%

Based on the estimated post tax IRR's in Table 50 above, the results showed that the biogas price fluctuation that might be encountered by the facility does not have a large impact on the Biomass/Cogen facility's economic viability, and so a low biogas price was not a severe risk. Also note that, as with the base cases, Option 4 (the gas combustion turbine) was the least affected by biogas price fluctuations and provided the best overall results.

Table 51: Sensitivity Financial Analysis Based on Compost Price Changes

Compost Price ($/T)	Base	$0	$10	$20	$30	$40	$50	$60	$70
Option 1: Post Tax IRR	12%	9%	10%	12%	13%	15%	16%	18%	19%
Option 2: Post Tax IRR	12%	9%	11%	12%	13%	15%	16%	17%	19%
Option 3: Post Tax IRR	12%	9%	10%	11%	13%	14%	15%	16%	18%
Option 4: Post Tax IRR	14%	12%	13%	14%	15%	16%	17%	18%	19%

Based on the estimated post tax IRR's in Table 51 above the results show that the compost price fluctuation that may be encountered by the facility does not have a large impact on the Biomass/Cogen facility's economic viability, and so a low compost price is not a severe risk. Also, Option 4 (the gas combustion turbine) was the least affected by compost price fluctuations and provided the best overall results.

Table 52: Sensitivity Financial Analysis Based on Tip Fee Changes

Tip Fee ($/T)	Base	($10)	$0	$10	$20	$30	$40	$50	$60
Option 1: Post Tax IRR	12%	-7%	-3%	1%	6%	10%	14%	18%	22%
Option 2: Post Tax IRR	12%	-5%	-1%	3%	6%	10%	14%	17%	21%
Option 3: Post Tax IRR	12%	-4%	-1%	3%	6%	10%	13%	16%	19%
Option 4: Post Tax IRR	14%	1%	4%	6%	9%	12%	15%	18%	20%

Based on the estimated post tax IRR's in Table 52 above, the results showed that the tip fee fluctuation that may be encountered by the facility does have a significant impact on the Biomass/Cogen facility's economic viability. The tip fee could become a severe risk if it goes too low and does not provide enough revenue to the Biomass/Cogen facility. However, it is worth noting that even with the more significant detrimental effects of tip fee fluctuation, Option 4 (the gas combustion turbine) was the least affected by compost price fluctuations and provided the best overall results. Option 4 was the only option that did not have a negative post tax IRR estimate, even when the Biomass/Cogen facility had to pay for feedstock material. Based on the results of Tables 51, 52 and 53, Option 4 would appear to be the best choice for energy cogeneration.

Project Options Incentive Financial Analysis Estimates

The financial analysis estimates using the base case scenario for options 1 through 4 provided for positive results. However, the post tax IRR estimated results were generally in the teens, and may not be high enough to clear corporate hurdles for investment due to associated risk factors. Typically corporations have minimum pre or post tax IRR hurdle rates of approximately 20% - 25%, with a senior debt coverage ratio approaching 2.0 considered a good result. The base case scenarios above are short of that benchmark. They can be supplemented, however, by incentives that help offset the cost of implementing the Biomass/Cogen project and improve the return to clear the financial analysis hurdles. The two basic forms of incentives would be capital offset funding and green power package premiums for product sales. Financial analysis results using these two incentives are provided below.

Capital Cost Offset Funding Scenarios:

Offset funding sources can be developed to help defray the capital cost of the Biomass/Cogen project, reduce project risk, and improve the return on investment to allow the project financial analysis to clear minimum hurdle rates. Capital cost offset funding can be developed via grant activity, pre-paid tolling fees with interested feedstock supply partners, and other methods. Appendix R provides a list of the public and private grant funding sources that could potentially apply to the Biomass/Cogen project. Since the Biomass/Cogen project is the first bioenergy cogeneration project linked to a paper mill, the concept could act as an important model for the Pulp and Paper Industry and related industries, justifying program interest in providing grant funding. Since the Biomass/Cogen project is a major project with high volumes, it is not unreasonable to assume that a capital cost offset program targeting 20% funding offset of the project capital cost could be developed. This would significantly improve the return on investment estimates, and provide for a more compelling opportunity. Tables 53, 54, 55 and 56 provide financial analysis estimate summaries for Options 1, 2, 3, and 4 using a 20% funding offset for capital cost.

Table 53: Option 1 Financial Analysis Estimate Summary with 20% Capital Offset Funding

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$26,206,481
Grant/Incentive Capital Offset Funding	($5,241,000)
Total Project Capital Cost	$22,721,321
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$1,569,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
SubTotal Product Sales Revenue	$3,102,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,589,478
Total Operational Cost	$5,015,027
Net Revenue	$4,026,227
EBITA	$5,319,727
Post Tax Internal Rate of Return (IRR)	15%
Pre Tax Internal Rate of Return (IRR)	18%
Senior Debt Service Coverage Ratio	1.86

Table 54: Option 2 Financial Analysis Estimate Summary with 20% Capital Offset Funding

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$29,940,981
Grant/Incentive Capital Offset Funding	($5,988,000)
Total Project Capital Cost	$25,959,031
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$2,145,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
SubTotal Product Sales Revenue	$3,678,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,634,292
Total Operational Cost	$5,059,841
Net Revenue	$4,557,413
EBITA	$5,850,913
Post Tax Internal Rate of Return (IRR)	15%
Pre Tax Internal Rate of Return (IRR)	18%
Senior Debt Service Coverage Ratio	1.80

Table 55: Option 3 Financial Analysis Estimate Summary with 20% Capital Offset Funding

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$32,007,402
Grant/Incentive Capital Offset Funding	($6,401,000)
Total Project Capital Cost	$27,750,908
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$2,145,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
SubTotal Product Sales Revenue	$3,678,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,659,089
Total Operational Cost	$5,084,638
Net Revenue	$4,532,616
EBITA	$5,826,116
Post Tax Internal Rate of Return (IRR)	15%
Pre Tax Internal Rate of Return (IRR)	17%
Senior Debt Service Coverage Ratio	1.68

Table 56: Option 4 Financial Analysis Estimate Summary with 20% Capital Offset Funding

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$37,976,481
Grant/Incentive Capital Offset Funding	($7,595,000)
Total Project Capital Cost	$32,925,911
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$4,211,198
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
SubTotal Product Sales Revenue	$5,744,254
Variable Cost	$2,425,549
Semi Variable Cost	$2,730,718
Total Operational Cost	$5,156,267
Net Revenue	$6,526,487
EBITA	$7,819,987
Post Tax Internal Rate of Return (IRR)	17%
Pre Tax Internal Rate of Return (IRR)	21%
Senior Debt Service Coverage Ratio	1.93

The use of offset funding significantly improves the return on investment parameters for each option compared to the base case results for each option. Based on the estimated post tax IRR's in the tables above, Option 4 would again appear to be the best choice.

Green Power Package Cases:

As previously mentioned, there are four main policy approaches to encouraging renewable energy development and these act as incentives for green power packages:

Renewable Portfolio Standards: Renewable Portfolio Standards (RPS) are a mechanism for creating demand. Utilities are required to have a minimum amount of renewable energy generation capacity within their systems.

Renewable Electricity Funds: Renewable Electricity Funds (REF) provide predictable funding sources for the development of renewable energy sources. Utilities are required to contribute to a fund that promotes renewable energy.

Net Metering: Net Metering allows customer-generators to sell back electricity to the utility when they are generating more than they need. This is, in essence, using the grid to "store" electricity.

Disclosure: Disclosure of the fuel mix on electricity bills helps educate the public and create demand for green pricing programs.

This new policy activity can help to provide premiums for green energy power sales and incentives to renewable energy and green power generation such as represented by the Biomass/Cogen facility. These policies can result in promoting a premium for green energy pricing such as the Biomass/Cogen's electricity production. There is potential to develop Green Packages that allow the energy to be sold to energy customers willing to pay a premium to promote green energy.

The only project options that allow for a green power package such as this are Options 3 and 4. Tables 57 and 58 provide green power financial analysis estimate summaries for Options 3 and 4, where a $0.05 per kWh green power pricing benchmark has been used for the electricity generated. It has been assumed that only the electricity resulting from the biogas is applicable for sale as green power.

Table 57: Option 3 Financial Analysis Estimate Summary with Green Power Pricing Premium

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$32,007,402
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$34,279,928
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$3,081,698
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$4,614,754
Variable Cost	$2,425,549
Semi Variable Cost	$2,659,089
Total Operational Cost	$5,084,638
Net Revenue	$5,468,616
EBITA	$6,762,116
Post Tax Internal Rate of Return (IRR)	14%
Pre Tax Internal Rate of Return (IRR)	16%
Senior Debt Service Coverage Ratio	1.59

Table 58: Option 4 Financial Analysis Estimate Summary with Green Power Pricing Premium

Parameter	Estimate
Total Production Tons (Feedstock Furnish)	165,200 tpy
Project Facility Capital Cost	$37,976,481
Grant/Incentive Capital Offset Funding	$0
Total Project Capital Cost	$40,672,811
Feedstock Tip Fee Revenue	$5,988,500
Energy Revenue (Biogas, Electrical, Steam)	$5,044,283
Compost Revenue	$1,243,130
Recyclables Revenue (Metals, Plastic, etc.)	$289,926
Subtotal Product Revenue	$6,577,339
Variable Cost	$2,425,549
Semi Variable Cost	$2,730,718
Total Operational Cost	$5,156,267
Net Revenue	$7,359,572
EBITA	$8,653,072
Post Tax Internal Rate of Return (IRR)	15%
Pre Tax Internal Rate of Return (IRR)	18%
Senior Debt Service Coverage Ratio	1.74

The use of green power packages to obtain a pricing premium improves the return on investment parameters for each option compared to the base case results for each option. Based on the estimated post tax IRR's in the tables above, Option 4 would again appear to be the best choice.

Future Work Requirements

Successful implementation of the Biomass/Cogen project requires that the eventual owner includes comprehensive business and engineering planning in the adopted formal project implementation program. This program will be the complete plan that involves final decision approval of technology choice(s), investment capital requirements, operational requirements, and all business factors leading to allocation of the financial and management resources necessary to reduce risk. The planning will define the requirements to implement the involved preliminary design, detail design and construction engineering aspects of the project implementation workscope, as well as the startup operations and full production. Depending on the owner's access and approach to capital, development time and project risk, the project can be implemented by Linpac addressing the future work requirements below.

The CCI/BTA technology and system allows for a relatively quick 'start to finish' completion timeline. The major project milestones typical for a project of this magnitude are as follows:

Preliminary Design Engineering and Cost Estimates Completed
Full Project Financing Acquired
Detailed Design Engineering Authorized
Long Term Equipment Order Placed
Detailed Design Engineering Completed
Building Contractor Selected
General Equipment Order

Building Construction Begins
Biomass/Cogen Special Equipment Delivery
General Equipment Delivery
Construction Installation
System Test and Start-up
Performance Guarantee Certification
Full Operations and Production

At the core of the implementation will be an Engineering Execution Plan. An example Engineering Execution Plan specific to Biomass Cogen's project requirements is provided in Appendix S. The Biomass/Cogen project will require future engineering services to appropriately detail, construct and startup the CCI/BTA based process and Linpac manufacturing site. These services include typical detail design engineering, construction engineering and management, startup services, and project administration workscope and tasks. The engineering services should also provide complete construction engineering, engineering start-up services and engineering project management. The task and workscope areas for engineering services typically include the following:

Detailed Design Engineering
Final Process Flow Diagram (PFD)
Final Detailed Process and Instrumentation Diagram (P&ID)
General Arrangements and Floor Plans
Equipment Foundation Requirements
Typical Sections
Structural Details
Tanks/Platforms/Support/Mounts/Anchors
Mechanical Equipment List
Electrical Motor, Conduit and Wiring Schedule
Electrical One Line
Electrical Control Diagram
Instrument Loops, Schedules and Specifications
Piping Isometrics
Mechanical, Electrical, and Civil Specifications
Final Construction Cost Estimate for Installation

Construction Engineering and Management
Construction Plans and Specifications
Construction Engineering and Planning
Final Construction Package
Vendor Equipment Procurement
Construction Installation Supervision
Contractor and Subcontractor Oversight
Vendor/Supplier Coordination
Change Order Review and Approval
Construction Management

Startup Services
Startup Planning and Requirements
Startup Onsite Supervision and Technical Support
Vendor Equipment and System Performance Verification
Biomass/Cogen SOP/JSA Manuals
Biomass/Cogen Maintenance Manuals
Startup/Operations Optimizations

Project Administration

Project Management and Administration
Project Cost Tracking
Project Monthly Progress Reports

The Biomass/Cogen installation will be environmentally friendly. The Biomass/Cogen is a low impact process with few air emission concerns, and relatively minor non-hazardous solid waste and effluent streams. Based on CCI's preliminary data and testing these are not seen as problematic. In addition to the environmental review, the solid waste and effluent permit issues will need to be addressed in detail. The permitting will need to be accomplished in a timely manner, in order to adhere to the project construction and startup schedule. No barriers to permitting considerations are evident, and the project parameters should allow for quick processing of permits.

Human resources, health and safety considerations will require adequate planning. The Biomass/Cogen processing equipment and system layout should be designed with manufacturing flow and surge protection that allows a minimum number of personnel to readily perform the operational, manufacturing and maintenance requirements. The CCI/BTA system itself is very "employee friendly**.**" A training period will be required for new employees working in the facility. This training period will allow new Linpac operators to understand the Standard Operating Procedures (SOP) and Job Safety Analysis (JSA) required to safely run the plant. A set of SOP/JSAs should be developed for this purpose and incorporated into plant operations to ensure the training, based on the SOP/JSA procedures, occurs prior to startup and on a continuing basis. The building site will need to be designed to accommodate the eventual layout. Recommendations for the building will include a review of fire hazards and safely practices, as well as individualized chemical containment and safety review. The building and facilities must have adequate outdoor access to allow for fire protection services to quickly respond to fires reported inside the building. The outside of the building must have adequate spacing and setbacks from roads and nearby buildings along with standard fire safety hydrants and equipment access.

Part of the business planning effort should include a legal and tax evaluation based on the project parameters. The project may require legal and tax review for these issues:

Ownership Arrangements
Project Capital Finance Package
Performance Guarantee(s)
Lease vs. Buy Assessment
Raw Material Supply Contracts
Product Sales Contracts (if initiated)

These areas are routine standard industry practices and no foreseeable problems are expected to arise or become critical to the project.

Conclusions

Based on the work the following conclusions can be made in each of the project's areas:

Feedstock Generation Survey and Waste Infrastructure:

- For available feedstock, the results based on a reasonable percent recovery factor for each sector shows that there are over 342,000 tons per year of total biomass in the State of South Carolina. This is enough to provide ample feedstock to the Biomass/Cogen facility.

- For available feedstock, the results show that if concerns about Animal Manure procurement are evident, then the non-manure subtotal shows that there are more than 346,000 tons per year of non-manure biomass available if South Carolina and the adjoining SERBEP States are targeted. This is enough to provide ample feedstock to the Biomass/Cogen facility.

- For available feedstock, using an average tipping fee of $40 per ton will supply enough total biomass feedstock from the regional areas to supply the Biomass/Cogen facility's needs, while an average tipping fee of $30 per ton will supply enough feedstock if non-manure biomass is targeted.

- Per the waste management infrastructure, many animal manure and related biomass waste generators currently do not pay a tip fee to dispose of their wastes, and are used to "zero" cost economics. Transportation costs present a large challenge in moving highly wet material such as animal manure or other wet biomass wastes long distances. Changing regulations, however, may serve to assign disposal costs directly to the industry, and encourage disposal alternatives for organic wastes, particularly animal manures, as a cost effective alternative. The concentration of certain biomass feedstock types and organic materials in certain regional areas provides an excellent opportunity for recovery.

Engineering and Site Permitting:

- The CCI/BTA technology is an effective anaerobic digestion technology which has provided reasonable justification that the BTA technology can effectively process the targeted animal manure and biomass raw materials and is technically feasibly and viable for use in the Biomass/Cogen operations to produce biogas for use as fuel.

- The CCI/BTA technology currently is used in various facilities in Europe and Canada. A plant tour and technical evaluation of the startup operations at the CCI Newmarket facility provided preliminary verification of the technology's feasibility for use in the Biomass/Cogen facility.

- The preliminary capital cost estimates for each scenario has been reasonably estimated. The options for cogeneration or boiler use of the biogas are based on reasonable assumptions and the chosen equipment provides for the use of the biogas as produced. These cost estimates appear to be sufficient to cover the cost of equipment and facility construction and installation, and start-up requirements to achieve full production and business operations.

  Based on CCI's existing Newmarket production data and results, as well as BTA data for European facilities, the operational cost estimates developed are reasonable for preliminary estimates for comparison and preliminary financial evaluation estimates.

- A review of the regulatory framework in South Carolina and the site specific requirements indicates that permitting of a CCI/BTA technology based biogas generation facility combined with cogeneration capability is feasible. Local land use and construction permits would require routine effort, with possible need for public hearings on land use. Environmental permits related to air quality, wastewater and storm water will likely require the greatest effort. In the biogas facility, the permitting for any disposition of liquid and solid residuals is probably the most critical aspect of the permitting process. Solid organic residuals of the quality expected from the CCI/BTA technology should be able to meet compost product standards for South Carolina and most of the SERBEP region. A minimum of six months should be allowed to obtain operating permits.

- The locations of the biogas and cogeneration facilities should be close to the Linpac linerboard mill to adequately service the mill, not more than a few miles away, so that biogas and/or electricity and/or steam may be cost effectively delivered to Linpac. As a result, essentially all potential locations will be within Spartanburg County. This is especially advantageous for air quality permitting, since Spartanburg County is in the least restrictive class of air quality regions.

Energy Markets:

- Current and future natural gas pricing is at a level on which it is reasonable to base a Biomass/Cogen facility development effort. The growth of the regional electricity market and deregulation effects provides for reasonable electrical pricing.

- While the South Carolina and the SERBEP states are behind the nation in renewable energy policy, future policy developments to promote renewable energy that could develop in these states would tend to improve the energy situation for a Biomass/Cogen facility. The future energy market provides for a good potential for sales, particularly as green power.

Financial Analysis:

- Based on the preliminary financial analysis estimates and results, Options 1, 2, 3 and 4 provided post tax IRR results that were in the teens, and are reasonably expected to be economically feasible. However, these base case results may not be high enough to clear typical return on investment hurdles required to adequately cover project risks.

- Based on the preliminary financial analysis estimates and results for the base case sensitivities pertaining to biogas, compost and tip fee fluctuations, Options 1, 2, 3 and 4 were not significantly sensitive to biogas or compost price fluctuation, but were sensitive to tip fee fluctuations. Tip fee revenue reduction could have a detrimental effect on the Biomass/Cogen's return on investment.

- Based on the preliminary financial analysis estimates and results for the offset funding scenario, using a 20% offset funding target, Options 1, 2, 3 and 4 showed improvement in the return on investment and financial analysis estimate results compared to their base case. Capital cost offset funding significantly improves each option's return on investment and helps to reduce the project risk.

- Based on the preliminary financial analysis estimates and results for the green power package scenario, using a $0.05 per kWh green power pricing target, Options 3 and 4 showed improved return on investment and financial analysis estimate results compared to their base case. Green power pricing premiums significantly improve Options 3 and 4 return on investment and reduces the project risk.

- Option 4 was determined to be the best opportunity based on its more positive return on investment results and key financial analysis parameters for the base case scenario, the offset funding scenario and green power package scenarios, as well as the less detrimental effects with regard to the base case sensitivity analysis scenarios for biogas, compost and tip fee fluctuations.